CANADA

National Energy Board

Reasons for Decision

CanStates Gas Marketing and
Transco Energy Marketing Company
Esso Resources Canada Limited
FSC Resources Limited
Ramarro Resources Inc.
Vector Energy Inc.
Western Gas Marketing Limited

GH-6-89

July 1990

Gas Exports

National Energy Board

Reasons for Decision

IN THE MATTER OF

Esso Resources Canada Limited

Application Under Part I of the *National Energy Board Act* for a Change, Alteration, or Variation of Licence GL-82

AND IN THE MATTER OF

CanStates Gas Marketing and Transco Energy Marketing Company
FSC Resources Limited
Ramarro Resources Inc.
Vector Energy Inc.
Western Gas Marketing Limited

Applications Under Part VI of the *National Energy Board Act* for Licences to Export Natural Gas

GH-6-89

July 1990

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Recital and Appearances

IN THE MATTER OF the *National Energy Board Act* and the regulations made thereunder;

AND IN THE MATTER OF an application dated 31 August 1989 by CanStates Gas Marketing and Transco Energy Marketing Company for a licence under Part VI of the Act for the exportation of natural gas; filed with the National Energy Board ("the Board") under File No. ER 7200-C280-1;

AND IN THE MATTER OF an application dated 27 November 1989 by Esso Resources Canada Limited for an order under Part I of the Act changing, altering or varying Licence No. GL-82 and assigning the Licence from Esso Resources Canada Limited to Esso Resources Canada Limited and Transco Energy Marketing Company; filed with the Board under File No. ER 7200-E14-3-2;

AND IN THE MATTER OF an application dated 15 February 1989, as amended, by FSC Resources Limited for a licence under Part VI of the Act for the exportation of natural gas; filed with the Board under File No. ER 7200-F58-1;

AND IN THE MATTER OF an application dated 28 July 1989, as amended, by Ramarro Resources Inc. for a licence under Part VI of the Act for the exportation of natural gas; filed with the Board under File No. ER 7200-R55-1;

AND IN THE MATTER OF an application dated 9 December 1989, as amended, by Vector Energy Inc., as agent for Canadian Pioneer Energy Inc., Norwest Oil & Gas Corp., Opinac Exploration Limited, Ranchmen's Resources Ltd., Total Petroleum Canada Ltd., Ulster Petroleums Ltd. and Wainoco Oil Corporation, for a licence under Part VI of the Act for the exportation of natural gas; filed with the Board under File No. ER 7200-V6-1;

AND IN THE MATTER OF an application dated 25 September 1989 by Western Gas Marketing Limited for a licence under Part VI of the Act for the exportation of natural gas; filed with the Board under File No. ER 7200-W35-5;

AND IN THE MATTER OF Hearing Order No. GH-6-89, as amended.

HEARD at Calgary, Alberta on 19, 20, and 21 March 1990.

BEFORE:

R.B. Horner, Q.C.	Presiding Member
A. Côté-Verhaaf	Member
D.B. Smith	Member

APPEARANCES:

S. Carscallen J.W. Ebert D. Glen P. Ogen	CanStates Gas Marketing and Transco Energy Marketing Company
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T.M. Hughes	Altresco Inc.
P.J. McIntyre	Amerada Minerals Corporation of Canada
W. Moreland	Amoco Canada Petroleum Company Ltd.
P. Budd	Boundary Gas, Inc.
H.T. Soudek	Consumers' Gas Company Ltd., The
B. Watson	Husky Oil Operations Ltd.
J. Hopwood, Q.C.	NOVA Corporation of Alberta
D.A. Dawson	Pan-Alberta Gas Ltd.
J. Burke-Robertson	Tennessee Gas Pipeline Company
J.M. Murray	TransCanada PipeLines Limited
G. Cameron	Union Gas Limited
S.F. McAllister	Alberta Petroleum Marketing Commission, The
J.A. Vockeroth	National Energy Board, The

Table of Contents

Tables

Figures

List of Appendices

Abbreviations

A&S	Alberta and Southern Gas Co. Ltd.
Act	*National Energy Board Act*
Adirondack	Adirondack Power, Inc.
ALF	Applicable Load Factor
Altresco	Altresco, Inc.
ANR	ANR Pipeline Company
APLP	Altresco Pittsfield, L.P.
Aqualon	Aqualon Company
ATV	Annual Triggering Volume
Beekmantown	Beekmantown Agri-Business Park, Inc.
Berkshire	Berkshire Gas Company
BG&E	Baltimore Gas and Electric Company
Board	National Energy Board
Canadian Pioneer	Canadian Pioneer Energy Inc.
CanStates	CanStates Gas Marketing
CanStates/TEMCO	CanStates Gas Marketing and Transco Energy Marketing Company
CNG	CNG Transmission Corporation
Columbia	Columbia Gas Transmission Corporation
Commonwealth Gas Pipeline	Commonwealth Gas Pipeline Corporation
Commonwealth Gas Services	Commonwealth Gas Services Company
Consolidated Agreement	Consolidated and Restated Agreement for the Sale and Purchase of Natural Gas, dated 24 June 1988, between Vector, the seven producers and Altresco Inc. as agent for APLP
Consumers' Gas	Consumers' Gas Company Ltd., The
DCQ	Daily Contract Quantity

DCV	Daily Contract Volume
DOE/FE	(United States of America) Department of Energy, Office of Fossil Energy
EARP Order	*Environmental Assessment and Review Process Guidelines Order*
ECCMP	Eastern Canada Core Market Price
EIA	Export Impact Assessment
Elizabethtown	Elizabethtown Gas Company
EME	Energy Marketing Exchange, Inc.
Empire	Empire Power, Inc.
ERCB	(Alberta) Energy Resources Conservation Board
Esso	Esso Resources Canada Limited
Falcon Canada	Falcon Seaboard Canada Limited
Falcon Gas	Falcon Seaboard Gas Company
Falcon Power	Falcon Seaboard Power Corporation
Falcon Resources	Falcon Seaboard Resources, Inc.
FERC	(United States of America) Federal Energy Regulatory Commission
FS	Firm Service
FSC	FSC Resources Limited
GECC	General Electric Capital Corporation
General Electric	General Electric Company
Georgia-Pacific	Georgia-Pacific Corporation
GJ	gigajoule(s)
Great Lakes	Great Lakes Gas Transmission Company
ha	hectare(s)
HCLP	Hopewell Cogeneration Limited Partnership
Imperial	Imperial Wallcoverings, Inc.
JCP&L	Jersey Central Power and Light Company
Kamine Milford	Kamine Milford Limited Partnership

LDC	local distribution company
LILCO	Long Island Lighting Company
m^3/d	cubic metres per day
MLC	MLC Oil and Gas Ltd.
MMBtu	million British thermal units
MMcf	million cubic feet
MMcf/d	million cubic feet per day
MW	megawatt(s)
MW.h	megawatt hour(s)
National Fuel	National Fuel Gas Supply Corp.
NEB	National Energy Board
NEES	New England Electric System
NEP	New England Power Corporation
NEPEX	New England Power Exchange
NEPOOL	New England Power Pool
North Country	North Country Pipeline Corporation
Norwest	Norwest Oil & Gas Corp.
NOVA	NOVA Corporation of Alberta
N.Y.	New York
NuGas	NuGas Ltd.
NYSDEC	New York State Department of Environmental Conservation
NYSEG	New York State Electric & Gas Corporation
NYSPSC	New York State Public Service Commission
Opinac	Opinac Exploration Limited
Panhandle	Panhandle Eastern Pipeline Company
PJ	Petajoule(s)
ProGas	ProGas Limited
PSE&G	Public Service Electric and Gas Company

PURPA	*Public Utility Regulatory Policies Act of 1978*
QF	qualifying cogeneration facility
RR/P ratio	remaining reserves-to-production ratio
Ramarro	Ramarro Resources Inc.
Ranchmen's	Ranchmen's Resources Ltd.
Riegel Products	Riegel Products Corporation
Rife	Rife Resources Ltd.
Saranac	Saranac Energy Company, Inc.
Signalta	Signalta Resources Ltd.
Southeastern	Southeastern Michigan Gas Company
Sulpetro	Sulpetro Limited
TEMCO	Transco Energy Marketing Company
Tennessee	Tennessee Gas Pipeline Company
the Commission	Public Service Commission of the State of New York
Total Petroleum	Total Petroleum Canada Ltd.
TransCanada	TransCanada PipeLines Limited
Transco	TransContinental Gas Pipe Line Corporation
TransGas	TransGas Limited
U.S.	United States of America
Ulster	Ulster Petroleums Ltd.
Union	Union Gas Limited
Vector	Vector Energy Inc.
Virginia Power	Virginia Electric and Power Company
WACOG	weighted average cost of gas
Wainoco	Wainoco Oil Corporation
WASP	weighted average selling price
WGML	Western Gas Marketing Limited

Chapter 1

Export Applications

1.1 Introduction

During the GH-6-89 proceedings, the National Energy Board ("the Board") heard five applications, filed under section 117 of the *National Energy Board Act* ("the Act"), for authorization to export natural gas, and one application, filed under section 21 of the Act, to amend and to assign an existing licence. The applications were filed by the following companies:

1. CanStates Gas Marketing and Transco Energy Marketing Company, as joint applicants ("CanStates/TEMCO");
2. Esso Resources Canada Limited ("Esso");
3. FSC Resources Limited ("FSC");
4. Ramarro Resources Inc. ("Ramarro");
5. Vector Energy Inc. ("Vector"); and
6. Western Gas Marketing Limited ("WGML").

The terms and conditions of the new or amended licences applied for and heard during the GH-6-89 proceedings are summarized in Table 1-1.

Table 1-1

Summary of Export Applications
GH-6-89

				Maximum Quantities Applied For		
Applicant (Type of Application)	**Buyer (Type of Market)**	**Term**	**Export Point**	**Daily 10^3m^3 (MMcf)**	**Annual 10^6m^3 (Bcf)**	**Term 10^6m^3 (Bcf)**
1. CanStates/TEMCO (new licence)	TEMCO (cogeneration plant)	1 Nov. 1990 to 31 Oct. 2005	Niagara Falls, Ontario	1 371.1 (48.4)	500.4 (17.7)	7 095.3 (250.5)
2. Esso (amend GL-82)	TEMCO (system supply)	To extend term of Licence GL-82 from 1 Nov. 1991 to 31 Oct. 2002	Niagara Falls, Ontario	2 125.0 (75.0)	775.6 (27.4)	9 152.4 (a) (323.1)
3. FSC (new licence)	Falcon Gas (cogeneration plants)	15 years commencing 1 Mar. 1991	Napierville, Québec	1 530.0 (54.0)	558.5 (19.7)	8 376.8 (295.7)
4. Ramarro (new licence)	EME (cogeneration plant)	1 Nov. 1990 to 31 Oct. 2005	Niagara Falls, Ontario	169.0 (6.0)	61.7 (2.2)	936.1 (33.0)
5. Vector (new licence)	APLP (cogeneration plant)	1 July 1990 to 30 Nov. 2005	Niagara Falls, Ontario	1 033.9 (36.5)	377.6 (13.3)	5 823.3 (205.6)
6. WGML (new licence)	Southeastern (system supply)	15 years commencing 18 Aug. 1990	Emerson, Manitoba	424.9 (15.0)	155.5 (5.5)	2 332.8 (82.4)

(a) Esso applied to increase the authorized term quantity by 9 152.4 10^6m^3 (323.1 Bcf), from 4 653.7 10^6m^3 (164.3 Bcf) to 13 806.1 10^6m^3 (487.4 Bcf). For the period 1 November 1990 to 31 October 2002, Esso applied for a total term quantity of 9 307.5 10^6m^3 (328.6 Bcf) which includes a quantity of 155.1 10^6m^3 (5.5 Bcf) already authorized under Licence No. GL-82 for the period 1 November 1990 to 31 October 1991. (i.e. 9 307.5 10^6m^3 (328.6 Bcf) minus 155.1 10^6m^3 (5.5 Bcf) equals 9 152.4 10^6m^3 (323.1 Bcf)).

1.2 Market-Based Procedure

The Board, in considering an export application, must take into account the requirements of section 118 of the Act which requires that the Board have regard to all considerations that appear to it to be relevant. In particular, the Board must satisfy itself that the quantity of gas to be exported does not exceed the surplus remaining after due allowance has been made for reasonably foreseeable Canadian requirements, taking account of trends in discovery.

To comply with the requirements of section 118 of the Act, the Board utilizes its Market-Based Procedure. The discussion of the Board's Market-Based Procedure that follows is general in nature and applies to each of the export applications heard in the GH-6-89 proceedings.

The Market-Based Procedure includes consideration of the following:

- complaints, if any, under the complaints procedure;
- an Export Impact Assessment ("EIA"); and
- any other factors that the Board considers relevant to its determination of the public interest.

1.2.1 Complaints Procedure

If Canadian gas users have been unable to obtain additional supplies of gas under contract on terms and conditions, including price, similar to those of the proposed export, they may complain to the Board. This provision of the Market-Based Procedure gives Canadian gas users an opportunity to object to an export application on these grounds.

1.2.2 Export Impact Assessment

The purpose of the EIA is to assist the Board in determining whether a proposed export is likely to cause Canadians difficulty in meeting their future energy requirements at fair market prices. When the Market-Based Procedure was first introduced, each export applicant was required to file an EIA which assessed the ability of Canadian natural gas producers to meet Canadian and export requirements for gas, the impact of the proposed export on domestic natural gas supply, demand and prices, and the ability of Canadian energy markets to adjust to these changes without difficulty.

Pursuant to a review of EIA filing requirements, which was conducted in the fall of 1989, the Board decided that, while it would continue to retain an EIA as part of its Market-Based Procedure, it would conduct its own assessment which would not be project-specific. Applicants now have the option of using the Board's analysis or of preparing and submitting their own analysis as a basis for arguing whether the proposed exports would result in adjustment difficulties in Canadian energy markets.

Accordingly, each applicant in the GH-6-89 proceedings was directed to advise the Board, and the interested parties, whether it intended to rely on the Board's most recent EIA, or on its own EIA.

1.2.3 Benefit-Cost Analysis

Benefit-cost analysis was a component of the Market-Based Procedure used to determine whether the benefits from a proposed export were likely to recover all the associated costs to Canada, including the incremental costs of producing and transporting the gas. A number of concerns with both the benefit-cost methodology and with the appropriateness of the use of the analysis for determining the public interest with regard to the proposed exports were raised primarily by producers, the governments of the producing provinces, and by U.S. importers. In response, pursuant to Hearing Order GHW-4-89, the Board held a written hearing on the continued appropriateness of applying benefit-cost analysis to export licence applications. As a result of its examination of all of the GHW-4-89 written submissions, the Board concluded that it would no longer use benefit-cost analysis as a determinative factor in licensing gas exports.

In a letter dated 15 March 1990, the Board informed all interested parties to GH-6-89 of this decision and noted that as a result, the applicants were not required to provide evidence on net social benefits and that, therefore, benefit-cost analysis would not be an issue in the GH-6-89 proceedings.

1.2.4 Other Factors Relevant to the Public Interest

1.2.4.1 Gas Supply

The Board conducts a review of the applicants' gas supply arrangements to assist it in determining

whether the proposed exports are in the Canadian public interest.

In its assessment of gas supply, the Board examined the adequacy of both reserves and productive capacity to support the applied-for exports.

Each export applicant provided estimates of remaining established reserves for those fields from which it intends to produce gas for the proposed export. The Board conducted geological and engineering analyses of each applicant's gas supply in order to prepare its own estimate of the applicant's marketable gas reserves.

In its evaluation of gas reserves, the Board made use of its gas reserves database, which is maintained and updated on an ongoing basis. The evaluation of gas reserves includes a nomenclature check for correlation purposes, volumetric studies of new pools, re-examination of developing pools and analysis of producing pools which includes reviewing production and pressure data. A review and an evaluation of the ownership and contractual status of all pools included in each of the applications were also conducted.

The Board's approach to the assignment of reserves for single-well pools is based on extensive studies on the performance and drainage of these pools. The results of this work were grouped by formation and area within Alberta. The study revealed a considerable variation in drainage areas, both regionally and by formation, with the Mannville sands having the smallest areal extent. The Board has generally adopted these results but applies them as a guideline only. In those cases where geological or other data is available which indicates that the guidelines are not appropriate, adjustments to the area assignments are reflected in the Board's reserves estimates. The Alberta Energy Resources Conservation Board ("ERCB") has also conducted a study of single-well pools and has adopted an approach to area assignments similar to that used by the Board.

The Board's approach to assignment of reserves to a discovery well and consideration of possible appreciation of reserves is consistent with the definition of established reserves. This definition makes reference to reserves specifically proven by drilling, testing or production, plus that judgment portion of reserves interpreted to exist from geological, geophysical or similar information, with reasonable certainty. Where the Board has geological or other evidence to suggest that a larger area assignment is warranted, reserves assigned to the discovery well include an estimate of appreciation. A portion of the area would generally be categorized as probable reserves and discounted by a risk factor. In addition, the Board has given consideration to potential reserves where an applicant provides evidence to demonstrate that the potential reserves will be under its control.

Estimates of reserves submitted by the applicants are for specific pools distributed throughout most areas and zones of Alberta, and for some pools in Saskatchewan. Pool sizes varied from small, single-well pools to very large, established pools. Generally, large pools tend to have been producing for a considerable period of time, while single-well pools have often not yet been placed on production.

In reviewing marketable gas reserves, the Board evaluated the number, size and distribution of pools for which each of the applicants had submitted estimates of reserves. In some cases, the Board's pool count was different from that of an applicant because the Board amalgamated or segregated pools on the basis of its interpretation of reservoir data. All references to pool counts in the following chapters are based on the Board's analysis.

The Board's estimates of reserves, along with basic deliverability data for each of the pools for which estimates of reserves were submitted by an applicant, were used in preparing productive capacity projections. Productive capacity projections are generally adjusted to reflect an applicant's expected requirements for gas. The adjusted productive capacity is the estimated productive capacity at any point in time, carrying forward for future use the productive capacity resulting from an earlier excess of productive capacity over production. The requirements shown for each of the applicants included in the productive capacity figures are based on an assumed load factor of 100 percent and may therefore somewhat overstate each applicant's actual supply requirements.

1.2.4.2 Transportation and Sales Contract Arrangements

The Board conducts its review of the transportation and gas sales contract arrangements to assist it in determining whether the proposed exports are in the Canadian public interest. The Board's review of

these commercial arrangements includes consideration of:

- the contractual commitments for the gas supply in the province of production;
- the upstream and downstream transportation arrangements;
- the contractual obligations entered into between the Canadian seller and the United States of America ("U.S.") buyer; and
- any resale arrangements that occur beyond the border sale point, if such arrangements could influence or affect the international sales agreement.

The Board reviews the gas sales contracts entered into between the Canadian seller and the U.S. buyer to determine whether the contracts:

- recover associated Canadian intraprovincial and interprovincial transportation costs;
- are likely to be durable over their term;
- ensure that the volumes contracted for will likely be taken; and
- have the support of the Canadian producers supplying the gas to the export project.

1.3 Cogeneration Plants

Four of the six gas export licence applications are for use by cogeneration facilities.[1] FSC has applied to export gas to three discreet cogeneration facilities, each with its own power purchase and steam sale agreements. Table 1-2 identifies the cogeneration projects for which export licence applications were filed.

In each case, the proposed cogeneration facility would employ combined-cycle technology, utilizing both combustion turbine and steam turbine-driven electrical generating equipment to improve conversion efficiency. Regulations issued under authority of the (U.S.) *Public Utility Regulatory Policies Act of 1978* ("PURPA"), require that a qualifying cogeneration facility ("QF"), in order to maintain its QF status, must have a thermal output, as process steam, exceeding five percent of the total energy output of the plant. Also, the total electrical energy, plus one-half of the thermal energy output, must exceed 45 percent of the total energy fuel input (42.5 percent if the thermal output is greater than 15 percent). Failure to meet PURPA operating efficiencies would cause a cogeneration project to lose its QF status.

Another criteria that must be met to maintain QF status, requires that the electric utility ownership in a QF must not exceed 50 percent.

The PURPA regulations require electric utilities to buy all of the electricity generated by a QF and, unless the electric utility and the QF otherwise agree, to pay the QF not more than the full avoided-cost of producing the electricity.

QF owners and electric utilities may make alternative arrangements whereby an electric utility may dispatch a cogeneration facility.[2]

Should QF status be lost, there appears to be nothing in the PURPA, or in the implementing regulations, that would prevent a cogeneration facility from regaining its QF status once it returns to compliance with the criteria for qualification.

Table 1-2

Cogeneration Projects for which Export Licence Applications Were Filed

Applicant	Cogeneration Project/ Capacity (MW)	Electrical Customer	Steam Customer	Annual Gas Volumes (Bcf/yr)
CanStates/ TEMCO	HCLP (356)	Virginia Power	Aqualon	17.7
FSC	Adirondack (80)	NYSEG	Imperial	)
	Empire (80)	NYSEG	Beekmantown (3 steam users)	) 20.0
	Saranac (80)	NYSEG	Georgia-Pacific	)
Ramarro	Kamine Milford (35)	JCP&L	Riegel Products	2.2
Vector	APLP (160)	NEP	General Electric	13.3
Total All Projects	791 MW			53.2 Bcf/yr

1 A cogeneration facility is defined as a facility that produces "electric energy and forms of useful thermal energy (such as heat or steam), used for industrial, commercial, heating, or cooling purposes, through the sequential use of energy". 18 C.F.R.s. 292.202(c) (1980)

2 Dispatch allows an electric utility to schedule and to control the production of electricity by a QF.

1.4 Environmental Screening (GHW-3-90)

On 8 February 1990, the Minister of Energy, Mines and Resources, the Honourable Jake Epp, wrote to the Board requesting clarification on how the Board complied or would comply with the *Environmental Assessment and Review Process Guidelines Order* ("EARP Order") in arriving at its decision to issue licences for the export of natural gas. In his response to the Minister, the Chairman of the Board advised that, in compliance with the EARP Order, the Board would be instituting a procedure to examine the potential environmental effects of the export proposals that are to be heard by the Board in its GH-6-89 proceeding. The purpose of the environmental screening was to enable the Board to reach one of the conclusions required in section 12 of the EARP Order. To that end, the Board held a written hearing, pursuant to Hearing Order GHW-3-90 wherein it considered submissions from the GH-6-89 applicants as well as submissions from all interested parties to GHW-3-90.

The GH-6-89 applicants filed with the Board environmental information concerning the potential environmental effects of the proposal and the social effects directly related to those environmental effects, including any effects that are external to Canadian territory.

Interested parties were served with the written submissions of the GH-6-89 applicants and were provided with an opportunity to provide their written views on the issues referred to in those submissions. The GH-6-89 applicants were then afforded an opportunity to reply to the written submissions from interested parties.

The Board has completed its environmental screening and has concluded that the potentially adverse environmental effects and the social effects directly related to those environmental effects, that may be caused by the export applications of Esso, FSC, Ramarro, Vector and WGML are insignificant or mitigable with known technology. The Board has made the following conclusions with respect to the potentially adverse environmental effects and the social effects directly related to those environmental effects that may be caused by the export application of CanStates/TEMCO:

a) upstream matters in Canada and gas transmission and downstream end-use in the U.S. - insignificant or mitigable with known technology; and

b) new gas transmission facilities required on the TransCanada system - not fully known as the matter is currently being addressed in accordance with proceedings being held pursuant to Hearing Order GH-5-89.

Chapter 2

CanStates Gas Marketing and Transco Energy Marketing Company

2.1 Application Summary

By joint application dated 31 August 1989, as amended, CanStates/TEMCO applied, under Part VI of the Act, for a new export licence to export gas at Niagara Falls, Ontario with the following terms and conditions:

Term	-	15 years commencing 1 November 1990
Maximum Daily Quantity	-	1 371.1 10^3m^3 (48.4 MMcf)
Maximum Annual Quantity	-	500.4 10^6m^3 (17.7 Bcf)
Maximum Term Quantity	-	7 095.3 10^6m^3 (250.5 Bcf)

In addition, the applicants have applied for a licence condition that would give the right to exceed the daily and annual quantities by up to five and ten percent, respectively, to allow for measurement differences and unaccounted for losses. As well, the applicants have applied for the right to export, during the remaining term of the licence, any volumes authorized for export that are not actually exported during any year, subject to the limitations of the daily and annual volumes.

CanStates is a partnership having as its partners GasTrade Inc. and CanStates Energy. CanStates Energy is itself also a partnership having as its partners Rankin Petroleum Marketing Ltd. and Polysar Hydrocarbons Limited. TEMCO, a subsidiary of Transco Energy Services Company, carries on business as an aggregator of various gas services.

The gas proposed for export would be purchased from 13 companies in Alberta and would be transported on the systems of NOVA Corporation of Alberta ("NOVA") and TransCanada PipeLines Limited ("TransCanada") to the Niagara Falls, Ontario export point. At the international border, the gas would be sold by CanStates to TEMCO. From the international border, the gas would be transported on the systems of National Fuel Gas Supply Corp. ("National Fuel"), including capacity on the Niagara Spur of Tennessee Gas Pipeline Company ("Tennessee"), TransContinental Gas Pipe Line Corporation ("Transco"), Commonwealth Gas Pipeline Corporation ("Commonwealth Gas Pipeline") and Commonwealth Gas Services Company ("Commonwealth Gas Services") for ultimate delivery to Hopewell Cogeneration Limited Partnership ("HCLP") for use in its cogeneration facility located near Hopewell, Virginia. To the extent that the gas is not delivered to the Hopewell plant, the gas would be delivered to other TEMCO markets.

The plant's power output will be sold to Virginia Electric and Power Company ("Virginia Power") and the steam will be sold to Aqualon Company ("Aqualon").

2.2 Complaints Procedure

The complaints procedure gives Canadian gas users an opportunity to object to an export proposal on the grounds that they have not had an opportunity to obtain additional supplies of gas under contract terms and conditions, including price, similar to those contained in the export proposal.

No complaints were received with respect to the CanStates/TEMCO export proposal.

2.3 Export Impact Assessment

CanStates/TEMCO elected to rely on the Board's most recent EIA. Based on that assessment, the applied-for export volumes would have little impact on Canadian production, consumption and prices of gas and Canadian energy users would not have any difficulty in meeting their future energy requirements as a result of the proposed export.

2.4 Gas Supply

2.4.1 Supply Contracts

CanStates has executed 15-year gas purchase contracts with thirteen producers, namely; Bounty Developments Ltd., Coho Resources Limited., Enron Oil Canada Ltd., MLC Oil and Gas Ltd. ("MLC"), NuGas Ltd. ("NuGas"), Paramount Resources Limited., Passburg Petroleums Limited., Phillips Petroleum Canada Ltd., Polaris Petroleums Ltd., Rife Resources Ltd. ("Rife"), Signalta Resources Limited ("Signalta"), Solex Energy Ltd., and Wellore Energy Inc.

Under the terms of the contracts, each of the producers has dedicated specific lands to CanStates. These lands are located in twelve areas of Alberta and one area in Saskatchewan. Four producers (NuGas, MLC, Rife, and Signalta) are also committed to provide additional reserves by 1 April 1990, under separate development contracts with CanStates.

The contracted gas supply will be used to satisfy two sales requirements. In addition to the applied-for TEMCO requirements, CanStates is contractually obligated to provide up to 850.0 $10^3m^3/d$ (30.0 MMcf/d) for 15 years to Alberta and Southern Gas Co. Ltd. ("A&S") under a separate sales arrangement. CanStates stated that, were there to be a constraint on gas supply, the gas would preferentially flow to A&S.

2.4.2 Reserves

Table 2-1 shows that the Board's estimate of CanStates' contracted remaining marketable gas reserves is 17 percent lower than CanStates' estimate, but exceeds the applied-for volume by 28 percent.

Although the Board's estimate of reserves exceeds the applied-for volumes, the Board notes that when the A&S volumes are also considered, the total combined requirements are greater than the Board's estimate of reserves.

The CanStates reserves estimate includes both established reserves and development reserves. Development reserves are potential reserves located on undrilled lands contracted to CanStates. The CanStates reserves estimate includes 9 999.0 10^6m^3 (353.0 Bcf) of established reserves and 955.0 10^6m^3 (33.7 Bcf) of development reserves.

Table 2-1

Comparison of Estimates of CanStates Remaining Marketable Gas Reserves with the Applied-for Term Volume
10^6m^3
(Bcf)

CanStates[1]	NEB[2]	Applied-for Volume[3]
10 954	9 100	7 096
(387)	(321)	(250)

1 As of 1 April 1990.

2 As of 31 December 1988.

3 In addition to the applied-for volume of 7 096.0 10^6m^3 (250 Bcf) for the TEMCO sale, CanStates is contractually obligated to provide a further 4 654.0 10^6m^3 (164.3 Bcf) to A&S under a separate sales arrangement.

The CanStates/TEMCO application included estimates of potential reserves on lands held by four of CanStates' producers. The Board's analysis of these potential reserves, discounted by an exploration risk factor, initially resulted in estimates similar to those submitted by CanStates. However, CanStates/TEMCO subsequently amended their application to reflect the results of recent drilling activity and therefore, included an undiscounted estimate of reserves for the NuGas lands in the established category. The Board does not have access to all of the recent drilling results and therefore, has continued to apply a risk factor to certain of the reserves which have been included in the established category.

A number of CanStates' single-well pools were assigned a full section drainage area by CanStates. CanStates stated that it relied to a great extent on reserves data submitted by the producers and that confidential geophysical control was used in two areas to define pool boundaries. In supporting full section assignments for single-well pools, CanStates also gave examples of single-well drainage greater than that supported by one full section of reserves, commented that single-well pools should be regarded as discovery wells and made reference to the ERCB appreciation factors. CanStates noted that some appreciation should occur and that many of the pools (45 percent) are

assigned less than a full section, reflecting the producers' best estimate of area. As noted earlier, the Board often assigns less than a full section to single-well pools, unless geological, engineering or other evidence suggests a larger area is appropriate.

The difference between CanStates' and the Board's reserves estimates can be attributed primarily to interpretation of area for some single-well pools and to the cumulative effect of other small differences in individual pools. These other differences are primarily due to parameters such as net pay and porosity. There is, however, a difference in reserves estimates due to pool area for the Jean Lake Field and a difference due to ownership interpretation in the Progress Doig C Pool.

In its analysis of CanStates' gas supply, the Board recognized 183 gas pools, the majority of which are not producing. Most of the pools are relatively small and located in the east-central portion of Alberta in Cretaceous zones. There are, however, a substantial number of Devonian pools. Sixty-seven percent of the pools for which CanStates submitted reserves are less than 100.0 10^6m^3 (3.5 Bcf) in size.

In summary, the Board's estimate of reserves is somewhat lower than that of CanStates but exceeds the applied-for volume for the TEMCO sale by a substantial amount. However, as noted earlier, CanStates is also contractually obligated to provide 4 654.0 10^6m^3 (164.3 Bcf) to A&S under a separate sales agreement. Both the Board's and CanStates' estimates of reserves are less than the combined requirements.

2.4.3 Productive Capacity

In order to assess the adequacy of CanStates' gas supply, the Board considered it necessary to compare projections of productive capacity relative to requirements under two sets of assumptions. The first scenario provides for the delivery of the TEMCO volumes at 100 percent load factor, which is the applied-for annual volume, and the A&S volumes at 100 percent load factor. Together, these volumes are CanStates' contractual requirements. The second scenario provides that the TEMCO and A&S volumes will be taken at load factors less than 100 percent. This represents CanStates' expected requirements and is consistent with the projection of requirements submitted by CanStates. The Board has assessed the adequacy of CanStates' gas supply under both sets of assumptions, as shown in Figures 2-1 and 2-2.

Figure 2-1 compares the Board's and CanStates' projections of annual productive capacity with the Board's assessment of CanStates' total requirements. The requirements include the applied-for volumes for the TEMCO sale, the A&S require-

Figure 2-1

COMPARISON OF CANSTATES' & NEB'S ESTIMATES OF ANNUAL PRODUCTIVE CAPACITY

(Requirements at 100% load factor)

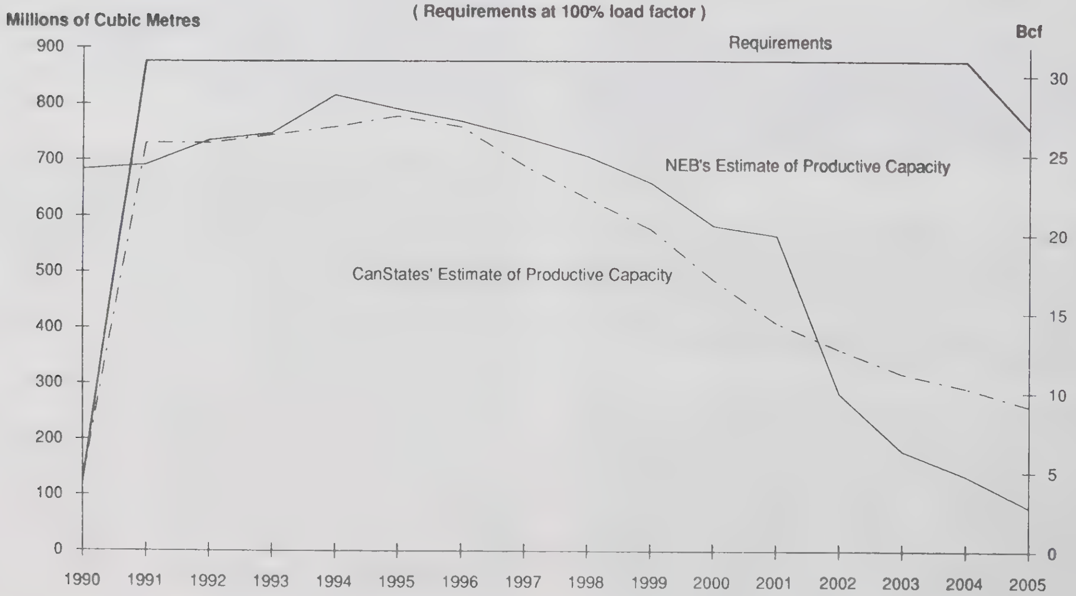
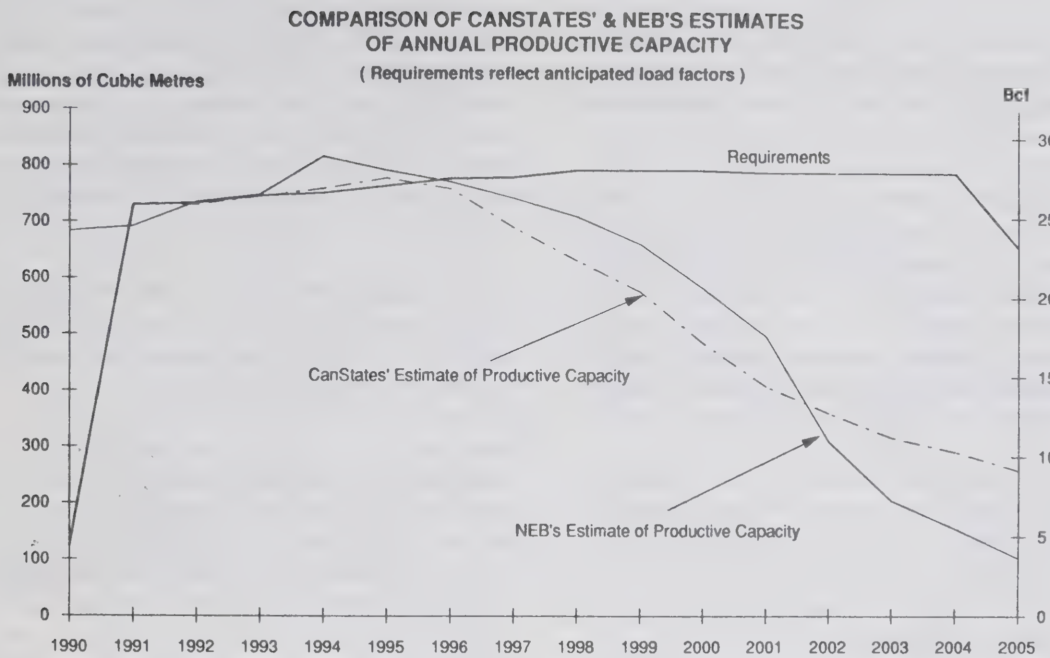


Figure 2-2



ments, fuel and shrinkage. In its assessment of productive capacity, the Board has accepted CanStates' assumption that deliverability from the development areas would have the same production profile as that for the established areas. Both the Board's and CanStates' projections suggest inadequate productive capacity throughout the proposed export term. Despite the Board's estimate of reserves being about 17 percent less than CanStates' estimate, the two projections have similar profiles because the Board assumed a somewhat higher rate of take than that used by CanStates.

Figure 2-2 shows CanStates' requirements with a 90 percent load factor applied to the TEMCO sale and a 70-90 percent load factor applied to the A&S volumes. Given these assumptions, both the Board's and CanStates' projections of productive capacity indicate that shortfalls in gas supply may begin in 1996.

CanStates commented that the projected future deficiency in gas supply was a consequence of the unwillingness of producers to commit reserves at this time at low rates of take. CanStates further argued that it would be significantly over-contracted, relative to deliverability requirements, if it were required to demonstrate full deliverability for the full 15-year term. CanStates stated that a backstopping arrangement with ProGas Limited ("ProGas") to provide up to 566.6 $10^3m^3/d$ (20.0 MMcf/d), on a "best efforts" basis, would be used to remedy day-to-day supply deficiencies. However, CanStates recognized that it would have to contract additional gas supplies to meet its total requirements throughout the proposed export term.

Views of Intervenors

Union Gas Limited ("Union") was the only intervenor providing views on CanStates' gas supply. Union was of the view that the deficiency in CanStates' productive capacity was too great to be remedied by additional development contracts. Union was also concerned that CanStates' gas supply was over-contracted with TEMCO and A&S and that A&S had priority to the limited available gas supply.

Views of the Board

The Board is of the view that CanStates has not demonstrated an adequate gas supply to meet contractual commitments to both TEMCO and A&S. The Board recognizes that contractual require-

ments based on a load factor of 100 percent may somewhat overstate CanStates' actual requirements, but notes that deficiencies in productive capacity relative to requirements are also evident using the projection of load factors submitted by CanStates.

The Board shares Union's concerns that, in times of a constraint on gas supply, the limited available supply would preferentially flow to A & S and not to the proposed TEMCO export market. In this regard, the Board notes that the expected load factors to the A & S market increase towards the end of the proposed term when the projected deficiencies in gas supply are most severe.

The Board concurs with CanStates that, although minor deficiencies in supply may be remedied by a "best efforts" backstopping arrangement with ProGas, CanStates would have to contract for additional gas to meet both its contractual and expected requirements.

2.5 Energy Removal Authorization

An application for an Alberta removal permit was filed with the ERCB on 20 October 1989. CanStates requested a volume of 8 009.8 10^6m^3 (283 Bcf) and a term of 15 years. CanStates stated that a decision is pending. At the time of the Hearing, it expected approval by the early summer of 1990. CanStates currently holds a two-year removal permit, which commences 1 November 1990.

At the time of the Hearing, CanStates stated that NuGas was in the process of applying to the Saskatchewan Department of Energy and Mines for a removal permit from that Province.

2.6 Market

The gas proposed for export will be purchased by TEMCO, the gas marketing arm of Transco Energy Services Company and one of the biggest non-pipeline marketers in the U.S. Since its creation in May 1985, TEMCO's sales have grown from 13 739.0 $10^3m^3/d$ (485.0 MMcf/d) to 52 067.0 $10^3m^3/d$ (1 838.0 MMcf/d) during the first six months of 1989. During 1989, TEMCO anticipates that approximately 55 percent of its gas supplies will be sold in the Eastern Seaboard area, 30 percent in the Texas and Louisiana Gulf Coast areas and 15 percent in the Midwest/Ohio Valley area. To satisfy its market requirements, TEMCO purchases gas from many producers in the Gulf of Mexico and in Canada under long-term and spot arrangements. TEMCO testified that in view of the Canadian pipeline demand charge commitments and the higher transportation costs, when compared with gas supply originating from the Gulf Coast area, it will likely attempt to match Canadian gas with specific markets.

In this regard, TEMCO testified that the proposed export would primarily be used as the principal gas supply for a 356 MW cogeneration plant under construction in Hopewell, Virginia.

The plant, which will be owned by HCLP, has been certified as a QF by the (U.S.) Federal Energy Regulatory Commission ("FERC") and will be fully dispatchable. The facility will have a capability of burning up to 2 266.2 $10^3m^3/d$ (80.0 MMcf/d) of gas, or an equivalent amount of No. 2 fuel oil.

TEMCO will be the exclusive supplier of gas to the Hopewell plant under an executed 15-year Amended and Restated Gas Sales Agreement between HCLP and TEMCO, dated 29 July 1988. When operating at a 100 percent load factor, approximately 1 359.7 $10^3m^3/d$ (48.0 MMcf/d) of the plant's requirements would be satisfied by CanStates' gas, when available, while 906.5 $10^3m^3/d$ (32.0 MMcf/d) would be supplied from the U.S. Gulf Coast. Initially, the plant will be supplied totally by U.S. gas, or by Canadian gas on an interruptible basis, when it begins commercial operations. CanStates testified that the plant was expected to be in commercial operations in early May 1990.

HCLP has signed a 25-year Power Purchase and Operating Agreement with Virginia Power for the sale of electricity produced by the plant. Virginia Power provides electrical service to approximately 1.7 million customers in the mid-Atlantic states of Virginia and North Carolina. The cogeneration plant will be capable of supplying an equivalent of 250,000 residential customers served by Virginia Power, whose market is currently growing at a rate of two percent per year.

In addition, HCLP will sell steam to Aqualon under a 25-year Steam Sales and Purchase Agreement dated 31 May 1988. Aqualon will use the steam in the manufacturing of polymer products.

TEMCO testified that because the plant is fully dispatchable, meaning that it may operate at some times and not at others, it is not possible to say how much gas will be consumed. When dispatched, it is expected to consume approximately 2 266.2 $10^3m^3/d$ (80.0 MMcf/d), at 100 percent load factor. When the plant is not dispatched, the daily requirement for gas will be between 226.6 to 283.3 $10^3m^3/d$ (8.0 to 10.0 MMcf/d) in order to produce steam for Aqualon. TEMCO testified that the Hopewell plant is expected to operate at a 50 percent annual load factor. While this would mean that, on an annual basis, the plant would use an average of 1 133.1 $10^3m^3/d$ (40.0 MMcf/d), TEMCO stated that it is expected that the plant will consume approximately 2 266.2 $10^3m^3/d$ (80.0 MMcf/d) during 183 days and approximately 226.6 $10^3m^3/d$ (8.0 MMcf/d) during the remaining 182 days of each year. However, TEMCO agreed that this is a theoretical construct of how the plant might operate, as the plant will be dispatched based on weather and on other factors.

A provision of the TEMCO/HCLP contract gives TEMCO the right to interrupt sales to the plant for up to 30 days each year. As a result, TEMCO has signed an agreement, dated 30 August 1989, with The Consumers' Gas Company Ltd. ("Consumers' Gas") whereby TEMCO will provide peaking and winter seasonal service of 1 371.1 $10^3m^3/d$ (48.4 MMcf/d) for up to thirty days from December to February inclusive, each year for a ten-year period starting in November 1990. In this regard, the applicants testified that they would not object to the Board reducing the applied-for annual volume of 500.4 10^6m^3 (17.7 Bcf) by the amount of the Consumers' Gas volume during the first ten years of the applied-for export licence.

Although the Hopewell plant is expected to be the primary market, TEMCO has the right to use any of CanStates' gas for delivery to its alternative U.S. markets. TEMCO was unable to specifically identify those markets.

TEMCO forecasts deliveries based on a load factor of between 90 and 100 percent for each year.

TEMCO has applied to the (U.S.) Department of Energy, Office of Fossil Energy ("DOE/FE") for import authorization. That approval was expected shortly.

Views of Intervenors

Union held the view that the applicants had not provided evidence to prove the existence of an export market. Union noted that there was no contractual obligation for the CanStates' gas to be delivered to the Hopewell plant. Union contended that, given that the plant will require, on an average annualized basis, 1 133.1 $10^3m^3/d$ (40.0 MMcf/d) (i.e. 50 percent load factor), most, if not all, of the plant's gas requirements could be met from U.S. sources. Union pointed out, that because the plant was fully dispatchable, the demand for gas could be as low as zero. It was Union's view that TEMCO's contention that the gas will be delivered to some alternative U.S. markets should be unacceptable to the Board. In Union's view, what is required is the identification of specific gas markets, supported by gas sales contracts.

2.7 Contractual Arrangements

2.7.1 Transportation

The gas will be transported on the NOVA and TransCanada pipeline systems to the Niagara Falls, Ontario export point. In the U.S., where TEMCO is responsible for transportation arrangements, the gas will be shipped from the international border to the Hopewell plant on the National Fuel, Transco, Commonwealth Gas Pipeline and Commonwealth Gas Services systems.

In Canada, various producers have secured transportation on NOVA and this capacity will be assigned to CanStates upon the commencement of production. In regard to transportation on TransCanada, CanStates has executed a Precedent Agreement dated 20 November 1989. The Agreement contemplates commencement of Firm Service ("FS") on 1 November 1991, but also makes provision for the start-up of deliveries prior to that date. The applicants testified that, although it would be difficult to predict when deliveries might begin, deliveries would probably be phased in during the spring of 1991. However, the applicants added that, for this to take place, one of the incremental requirements identified by TransCanada in the GH-1-89 proceedings would have to drop out.

In the U.S., TEMCO has entered into agreements with all applicable pipeline systems for firm transportation services from the Canada/U.S. border to the Hopewell plant. The facilities necessary to transport the gas in the U.S. are subject to approval by the FERC. At the time of the GH-6-89 Hearing, those decisions were pending.

2.7.2 Gas Sales Contract

The gas proposed for export would be sold by CanStates to TEMCO, which, in turn, could sell the gas to HCLP. The applicants filed an executed copy of a Long Term Gas Sale Contract, dated 1 August 1989, between CanStates and TEMCO. The applicants also filed an executed Amended and Restated Gas Sales Agreement between TEMCO and HCLP, dated 29 July 1988.

The Long Term Gas Sale Contract provides for a Contract Demand of 1 371.1 $10^3m^3/d$ (48.4 MMcf/d) for a period of 15 years, and includes a take and pay provision, such that TEMCO is obligated to pay for at least 70 percent of the Annual Volume (i.e. the Contract Demand multiplied by the number of days in the year).

The Contract includes a two-part pricing structure consisting of a demand charge and a commodity charge.

Each month, TEMCO is to pay CanStates a demand charge equal to the sum of the demand transportation toll (which will be paid regardless of whether or not gas is delivered) and the commodity transportation toll associated with service on the Canadian pipelines.

The monthly commodity charge to be paid by TEMCO is equal to the Wellhead Price for the month multiplied by the quantity of gas delivered, where the Wellhead Price is calculated as follows:

Wellhead Price (in U.S. dollars/MMBtu) = A - X

where:

A = the weighted average selling price of all gas produced in the U.S. and offshore U.S. and sold by TEMCO to purchasers in the U.S. during the immediately preceding month, minus all transportation costs and expenses incurred in delivering all such gas from the various points of purchase by TEMCO to the various points of sale thereof by it (i.e. the TEMCO weighted average selling price or ("WASP"))

and where:

X= an amount between $0.54 and $0.59, varying with the (monthly) Applicable Load Factor ("ALF"), as set out below:

Amount	ALF
$0.59	0 - 25%
$0.58	26 - 35%
$0.57	36 - 45%
$0.56	46 - 55%
$0.54	Over 55%

where:

the ALF is to be determined as follows:

$$\text{ALF} = \frac{C}{B \times 80 \text{ MMcf/d}}$$

where:

B = the number of days in the month, and

C = the sum of the volumes of gas actually acquired from all sources for the Hopewell plant and volumes delivered under the Consumers' Gas/TEMCO Peaking and Winter Service Purchase Contract, dated 30 August 1989.

Regardless of the foregoing, TEMCO has agreed to pay CanStates a minimum monthly commodity charge of $0.95 (U.S.) per MMBtu.

The Contract contains no provision for renegotiation. The applicants held the view that such a provision was unnecessary because the Contract is very market-responsive inasmuch as it varies from month to month with the TEMCO WASP, which reflects the market value of gas.

2.7.3 Power Sales Agreement

The proposed sale of electricity from the Hopewell plant, a QF facility that was expected to be in commercial operation in May 1990, will be pursuant to the Power Purchase and Operating Agreement, dated 15 June 1987, as amended, between HCLP and Virginia Power. The Agreement will continue in effect for a period of twenty-five years from the first date of commercial operation of the plant and may be extended for periods of up to five years.

The Hopewell plant will be economically dispatched by Virginia Power. Dispatch of the facility requires Virginia Power to pay both a capacity charge and an energy charge to the HCLP. The sale of electricity from the Hopewell plant does not require wheeling by third parties.

2.7.4 *Thermal Energy Sales Agreement*

The proposed sale of steam from the Hopewell plant will be pursuant to the Steam Sale and Purchase Agreement, dated 31 May 1988, between HCLP and Aqualon. The Agreement, will continue for a period of twenty-five years from the date that the cogeneration facility first delivers steam to Aqualon. The Agreement is conditioned such that it may be extended beyond its initial twenty-five year term.

Aqualon, a manufacturer of polymer products, is obliged to purchase sufficient quantities of steam so that the Hopewell plant will maintain its QF status. The Agreement provides for the development of alternative steam uses if it appears either party thereto may fail to meet its obligations. The Agreement also includes provisions for compensation by the HCLP if the Hopewell facility cannot provide the steam required by Aqualon.

Views of the Board

The Board is satisfied that the CanStates/TEMCO Contract provides for the recovery of all fixed transportation costs in Canada by virtue of the inclusion of a demand charge component in the pricing provision, by which payment of demand charges will occur regardless of whether or not gas is delivered.

The commodity charge component of the export price is designed so that the delivered price of the gas will be competitive with prices of gas in the U.S., primarily with U.S. gas supply originating in the U.S. Gulf.

The Board is of the view that the pricing provisions of the Contract permit adjustments in the export price to reflect changing market conditions.

The CanStates/TEMCO Contract contains a provision for a minimum annual volume equal to 70 percent of the annual contractual volume. This volume must be paid for regardless of actual takes of gas. In addition, as previously mentioned, the demand charges will be paid no matter how much gas is actually delivered.

For the reasons cited above, the Board believes that it is reasonable to expect that the export proposal is likely to operate at a high load factor, thus ensuring a high level of take under the Contract.

With regard to markets, CanStates identified TEMCO and Consumers' Gas as the primary markets. While contractual arrangements have been put in place such that some or all of the gas could ultimately be delivered to the Hopewell plant, the Board recognizes that there is no certainty that this will happen in view of the fact that this facility is dispatchable. In this regard, the Board acknowledges Union's opposition to the CanStates/TEMCO export project on the basis that the applicants have failed to demonstrate the existence of a specific export market. However, the Board notes that TEMCO's sales have grown from 13 739 $10^3m^3/d$ (485.0 MMcf/d) during the first half of 1985 to 52 067 $10^3m^3/d$ (1 838.0 MMcf/d) during the first six months of 1989. Therefore, the Board takes comfort in TEMCO's demonstrated ability to market gas. As a result, the Board is satisfied that there will be a market for the CanStates' gas. Likewise, the Board is satisfied that TEMCO has the ability to market that gas in its other U.S. markets. Therefore, the Board has not been persuaded by Union's argument that the applicants have failed to provide adequate evidence related to markets.

The Board is satisfied with CanStates' evidence of producer support for the proposed export sale.

2.8 Disposition

The Board has decided to issue a new gas export licence to the applicants, CanStates and TEMCO, as joint licence holders, subject to approval of the Governor in Council. In order to accurately indicate the legal entities that will hold the licence, the Board has decided to issue the licence to GasTrade Inc., Polysar Hydrocarbons Limited and Rankin Petroleum Marketing Ltd. carrying on business together in partnership as CanStates Gas Marketing and to Transco Energy Marketing Company. The Board wishes to remind CanStates/TEMCO that should CanStates or CanStates Energy experience any change in the membership partners, a licence transfer under subsection 21.1(1) of the Act would have to be authorized by the Board and approved by the Governor in Council.

Appendix I contains the terms and conditions of the export licence, including a condition that the term of the export licence shall commence on the date of Governor in Council approval thereof and end on 31 October 1992 unless exports have commenced on or before 31 October 1992, in which case the term will end on 31 October 2002.

The authorized annual quantity in the first ten years of the export licence has been set at 459.3 10^6m^3 (16.2 Bcf) to reflect TEMCO's peaking service and winter seasonal service arrangement with Consumers' Gas for 1 371.1 $10^3m^3/d$ (48.4 MMcfd) for up to 30 days during the winter period over a ten-year period commencing 1 November 1990 (i.e. 500.4 $10^6m^3/a$ (17.7 Bcf/yr) minus 1 371.1 $10^3m^3/d$ (48.4 MMcfd) x 30 days equals 459.3 $10^6m^3/a$ (16.2 Bcf/yr)).

As more fully described in Chapter 1, in arriving at its decision the Board has used its Market-Based Procedure to determine, *inter alia*, whether the volumes to be exported are surplus to reasonably foreseeable Canadian requirements. The Board has noted the absence of any complaints to the proposed export.

CanStates elected to rely on the Board's EIA, which demonstrated that the exports would have little or no impact on total production, gas prices or Canadian consumption patterns and that Canadian energy users would not have any difficulty in meeting their future energy requirements. Based on its review of these matters, the Board is satisfied that the proposed export is surplus to reasonably foreseeable Canadian requirements.

As part of its Market-Based Procedure, the Board also assessed a number of public interest factors, including gas supply, markets, gas sales contracts, and transportation arrangements associated with the proposed export.

The Board reviewed CanStates' gas reserves and productive capacity and compared these estimates with it's own evaluation of CanStates' supply. The Board is not satisfied that CanStates has demonstrated adequate gas supply to meet the requirements over the entire term of the proposed export licence. In reaching this determination, the Board has considered CanStates' obligations to both TEMCO and A&S, the range of load factors which may be applicable to the proposed sales, and the extent to which the proposed export is supported by established reserves. Consequently, the Board has decided to issue a licence with a term ending in 2002, rather than in 2005 as was applied for. The term volume of the licence will be 5 593.8 10^6m^3 (197.5 Bcf).

Having reviewed the CanStates/TEMCO Contract, the Board is satisfied that it was negotiated at arm's length, that it is of commercial substance, and that it is likely to endure throughout its term.

Chapter 3

Esso Resources Canada Limited

3.1 Application Summary

By application dated 27 November 1989, Esso has applied, under Part I of the Act, to vary its gas export Licence No. GL-82[1] as follows:

(i) to extend the term of the Licence from 1 November 1991 to 31 October 2002;
(ii) to increase the maximum daily and annual quantities, during the period 1 November 1990 to 31 October 1991, from 425.0 10^3m^3 (15.0 MMcf) and 155.1 10^6m^3 (5.5 Bcf), respectively, to 2 125.0 10^3m^3 (75.0 MMcf) and 775.6 10^6m^3 (27.4 Bcf), respectively;
(iii) to authorize, during the period 1 November 1991 to 31 October 2002, maximum daily and annual quantities of 2 125.0 10^3m^3 (75.0 MMcf) and 775.6 10^6m^3 (27.4 Bcf), respectively;
(iv) to increase the term quantity by 9 152.4 10^6m^3 (323.1 Bcf), to 13 806.1 10^6m^3 (487.4 Bcf); and
(v) to include daily and annual operating tolerances of ten and two percent, respectively.

Esso also applied for an order, under Part I of the Act, authorizing the transfer of Licence No. GL-82 from Esso to Esso and TEMCO, as joint licence holders.

The applied-for licence extension would allow for the continuation of export sales which Esso and its predecessor, Sulpetro Limited ("Sulpetro"), have been making to TEMCO, and its predecessor, Transco, since 1980.

The gas is to be sold to TEMCO for resale to three U.S. local distribution companies ("LDCs"), namely:

- Public Service Electric and Gas Company ("PSE&G");
- Baltimore Gas and Electric Company ("BG&E"); and
- Long Island Lighting Company ("LILCO").

The TEMCO gas purchases are to be used as system supply and, to the extent that the LDCs are unable on any one day to take the full export volume, TEMCO intends to sell any remaining volume to its alternative markets. The gas to be exported over the extended term of the Licence will originate from fields located in Alberta and will be shipped via the NOVA and TransCanada systems to the international border at Niagara Falls, Ontario. From the border, the gas will be transported to the city gates of the three LDCs utilizing the facilities of Tennessee, National Fuel and Transco.

TEMCO, a State of Delaware corporation, is affiliated with Transco and Texas Gas Transmission Corporation. TEMCO is a wholly-owned subsidiary of Transco Energy Services Company, which is in turn a wholly-owned subsidiary of Transco Energy Company and is described by Esso as one of the largest non-pipeline marketers of gas in the U.S.

3.2 Complaints Procedure

The complaints procedure gives Canadian gas users an opportunity to object to an export proposal on the grounds that they have not had an opportunity to obtain additional supplies of gas

1 Licence GL-82, originally issued to Sulpetro, authorized exports to Transco, for the period ending 31 October 1991. In February 1987, Transco assigned, conveyed, and transferred to TEMCO its rights arising out of the Sulpetro/Transco Gas Sale Contract. In December 1987, Esso finalized the purchase of Sulpetro's assets and Sulpetro transferred and assigned to Esso all of its interests in the Sulpetro/TEMCO Gas Sale Contract. Since January 1988, Esso has been exporting gas to TEMCO under short-term export orders issued by the Board. Since April 1988, those short-term export orders have been jointly held by Esso and TEMCO. In April 1988, the Board issued Order MO-4-88 authorizing the assignment and transfer of Licence GL-82 from Sulpetro to Esso.

under contract terms and conditions, including price, similar to those contained in the export proposal.

No complaints were received with respect to the Esso export proposal.

3.3 Export Impact Assessment

Esso chose to rely on its own EIA, rather than on the Board's. The conclusion of Esso's assessment was similar to the Board's, that is, the applied-for export volumes would have little impact on Canadian production, consumption and prices of natural gas and Canadian users would not have any difficulty in meeting their future energy requirements as a result of the proposed exports.

3.4 Gas Supply

3.4.1 Supply Contracts

Since Esso intends to supply the proposed export licence extension with gas from its own pools, no gas supply contracts were required. The Board notes that no specific pools have been contractually dedicated to the export, but rather Esso submitted a list of uncontracted pools from which it intends to provide the required volumes.

3.4.2 Reserves

Esso used ERCB data as the basis for its reserves estimates and, in cases where less than 100 percent of the pool was owned, applied its ownership percentage to determine its net interest. Table 3-1 shows that the Board's estimate of Esso's reserves is approximately eight percent lower than Esso's estimate but that it is considerably larger than the applied-for term volume.

The difference in estimates of reserves arises predominantly from the manner in which Esso has adjusted the ERCB reserves estimates to account for future reserves appreciation. Esso based its methodology for estimation of reserves appreciation on statistical reserves appreciation data prepared by the ERCB. Throughout the productive lives of many pools, estimates of established reserves may be increased, or appreciated, as the pools are developed and the limits of the reservoirs are defined. The ERCB calculates the ratio of present reserves estimates to discovery year estimates. This data is published annually and shows the historical summary of appreciation factors, based on discovery year, for all gas pools with initial established reserves greater than 300 10^6m^3 (10.6 Bcf). Esso adopted this data and applied it to 132 gas pools in 18 fields. This resulted in an overall estimate of potential appreciation of 1 419 10^6m^3 (50.0 Bcf), which represents an upward adjustment to the ERCB reserves estimates for these pools. Esso acknowledged that the methodology used to determine reserves appreciation is statistical in nature and is not based on a geological interpretation of the pools in question . Esso also confirmed that there is no assurance that the pools will appreciate onto lands in which Esso has an ownership position.

Table 3-1

Comparison of Estimates of Esso's Remaining Marketable Gas Reserves with the Applied-for Term Volume
10^6m^3
(Bcf)

Esso[1]	NEB[2]	Applied-for Volume
20 382 (719)	18 799 (664)	9 152 (323)

1 As of 31 December 1989.
2 As of 31 December 1988.

The Board has considered Esso's approach to reserves appreciation and for several reasons considers it to be somewhat overstated. The Board has concerns regarding the broad application of reserves appreciation without an in-depth geological or engineering analysis of the relevant pools. The Board also notes that the ERCB analysis does not include appreciation data from pools with volumes less than 300 10^6m^3 (10.6 Bcf), yet Esso appreciated pools regardless of their size, including some below 300 10^6m^3 (10.6 Bcf). In addition, Esso may not have the lands under contract where appreciation could occur.

While recognizing that some appreciation is likely to occur in the 18 fields denoted, in view of the above concerns, the Board has chosen not to assign a specific estimate of appreciation to the Esso reserves estimate. In doing so, the Board is also cognizant of the fact that the appreciated reserves

comprise only seven percent of the established contracted reserves in Esso's application.

The remaining difference in estimates of reserves arises primarily from the cumulative effect of small differences for individual pools.

In its analysis of Esso's gas supply, the Board recognized 376 pools, all of which are in Alberta. These pools are distributed throughout the Province and include all significant producing zones, although the majority of the pools are concentrated in Cretaceous zones. Sixty-seven percent of the pools for which Esso has submitted estimates of reserves are under 100.0 10^6m^3 (3.5 Bcf) in size; however, the majority of the net remaining reserves (64 percent) are found in pools whose initial marketable reserves are estimated to be larger than 3 000.0 10^6m^3 (106 Bcf).

In conclusion, the Board's estimate of reserves exceeds the applied-for term volume by a substantial amount. However, the Board's estimate of reserves is somewhat lower than that of Esso, primarily because the Board did not include an estimate of reserves appreciation in its evaluation.

3.4.3 Productive Capacity

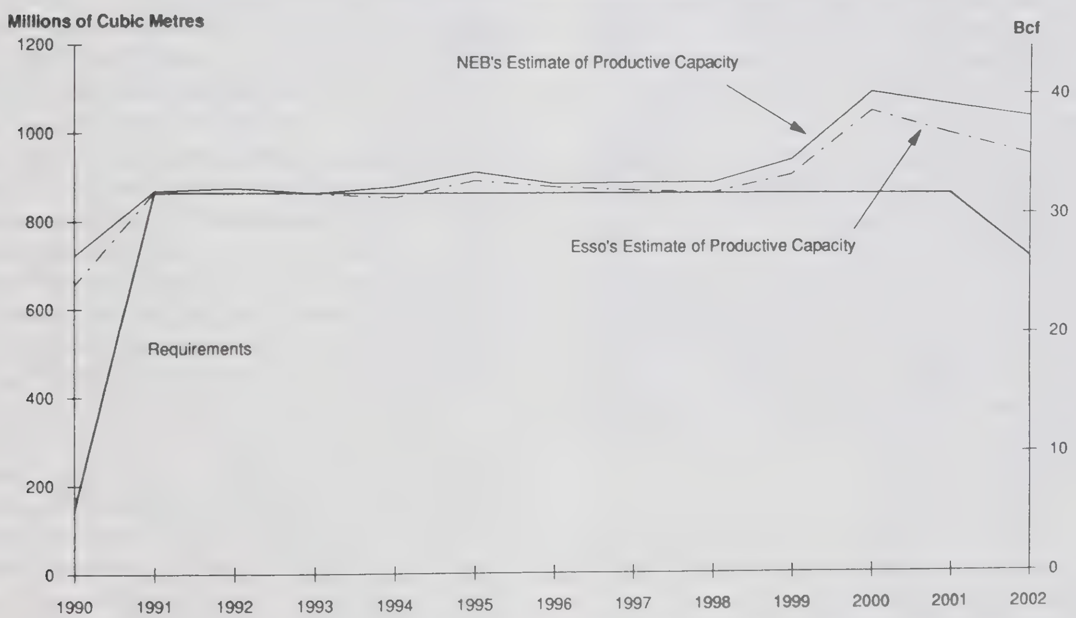
A comparison of the Board's and Esso's projections of productive capacity with the applied-for volumes, including fuel and shrinkage, is shown in Figure 3-1.

Both the Board's and Esso's projections indicate adequate productive capacity throughout the term of the proposed export licence extension. While both the Board's and Esso's estimates of reserves are substantially higher than the applied-for term volume, this is not reflected in the projections of productive capacity relative to requirements. This can be explained by the timing of the commencement of full blowdown for the large Bonnie Glen D-3A and Wembley/Valhalla Halfway B pools. These blowdowns are not expected to commence until approximately the year 2000; consequently, approximately 30 percent of Esso's submitted gas supply is unavailable until after the end of the proposed licence extension.

Esso provided detailed information on its overall corporate supply and requirements. On a corporate basis, Esso has a surplus of supply relative to

Figure 3-1

COMPARISON OF ESSO'S & NEB'S ESTIMATES OF ANNUAL PRODUCTIVE CAPACITY



requirements throughout the term of the proposed export licence extension. Esso stated that it could rely on its corporate gas supply to alleviate minor deliverability shortfalls.

Esso also suggested that minor deliverability shortfalls could be remedied by larger deliverability surpluses in other years, additional deliverability from reserves appreciation and accelerating the pace of development of certain pools.

Views of the Board

The Board is satisfied with Esso's supply position based on the specific pool information which has been submitted. The Board is further assured that shortfalls in deliverability will be remedied by Esso's corporate gas supply.

3.5 Energy Removal Authorization

Esso currently holds removal permit GR 88-50. On 16 March 1990, Esso applied to the ERCB for an extension of the term and an increase in volume. At the time of the GH-6-89 Hearing, the ERCB's decision was pending.

3.6 Market

Under the authority of Licence GL-82, amended as applied for, Esso/TEMCO, as joint licence holders, propose to sell gas to TEMCO, for resale to three U.S. LDCs, namely, PSE&G, BG&E, and LILCO.

Esso indicated that the three LDCs have been purchasing interruptible gas from TEMCO for approximately two years, which has been exported under the authority of jointly-held short-term export orders issued to Esso and TEMCO. Esso indicated that the prices paid by the LDCs for this interruptible supply were significantly higher than were being paid for alternative spot supplies since the LDCs anticipated firming up this short-term, interruptible supply into long-term, firm incremental supply in the near future.

TEMCO is one of the largest, non-pipeline marketers of gas in the U.S., whose total annual sales, since its establishment in June 1985, were shown to have increased from 5 000.0 10^6m^3 (177.0 Bcf) to 16 800.0 10^6m^3 (594.0 Bcf) in 1988. In 1989, TEMCO purchased and sold in excess of 17 300.0 10^6m^3 (610.0 Bcf) of gas, or some three percent of total U.S. gas consumption. As a gas supply aggregator, TEMCO purchases gas under long-term and spot arrangements from gas producers located in the Gulf of Mexico, Mid-Continent, and in Canada, for resale to customers located on the U.S. eastern seaboard, in the Texas and Louisiana Gulf Coast areas, and in the Midwest/Ohio Valley areas. In 1989, approximately four percent of TEMCO's gas supply originated in Canada. TEMCO's long-term policy is to negotiate market responsive gas purchase and gas sales arrangements.

Esso noted that, to the extent that the three U.S. LDCs do not take the full export volumes under the TEMCO/LDC gas sales arrangements, TEMCO intends to sell any remaining gas to its alternative U.S. markets and thereby, maintain a high level of take under the Esso/TEMCO Gas Sales Contract.

TEMCO has entered into three separate long-term gas sales agreements with each of its three LDC customers.

PSE&G is a regulated utility providing both gas and electric services and is the largest energy utility in New Jersey and is one of the largest combination electric and gas utilities in the U.S.

PSE&G furnished a gas supply and requirements forecast for the period through to the year 2002 which showed supply deficiencies starting in 1990. PSE&G forecasted a total market growth of 11.9 percent in the initial years of the forecast, largely on the strength of what it sees as a good potential for increased gas sales in the residential and in the power generation markets (i.e. cogeneration). Total requirements were forecasted to be 9 460.0 10^6m^3 (334.0 Bcf) in 1990, 13 116.0 10^6m^3 (463.0 Bcf) in 1995 and 13 825.0 10^6m^3 (488.0 Bcf) in 2000, up from 1989 actuals of 8 300.0 10^6m^3 (293.0 Bcf). In addition, interruptible gas sales to the industrial market were forecasted to continue to be strong owing to increasing concerns regarding the environment.

The forecast assumed that PSE&G would continue its current practice of minimizing gas supply costs through, among other means, the displacement of higher cost supply with spot gas purchases, and through the conversion of portions of its sales contracts to firm service transportation contracts with accompanying gas supply contracts.

PSE&G indicated that its forecast, and the assumptions upon which it was based, were realis-

tic and demonstrated a need for the Canadian imports available under the Esso/TEMCO export proposal.

BG&E is a combination electric and gas utility serving Maryland, including the city of Baltimore, and distributes gas purchased from Columbia Gas Transmission Corporation ("Columbia") and CNG Transmission Corporation ("CNG"). In addition, BG&E purchases gas directly from gas producers and marketers for which BG&E has entered into transportation service agreements with Columbia, CNG and Transco. In addition, BG&E provides transportation service for direct purchase customers. Transportation service accounts for approximately 37 percent of BG&E's system throughput.

BG&E provided a gas supply and requirements forecast for the period through to the year 2002 which demonstrated a need to increase firm supplies to satisfy peak demands. BG&E's forecast showed that without the Canadian gas available under the TEMCO supply arrangement, BG&E's firm daily supplies would fall short of peak-day demand by the 1995-96 winter, whereas hourly shortages were forecasted to occur as early as the 1990-91 winter. For this reason, BG&E indicated that it was anxious in seeing the TEMCO supply arrangement go forward for the 1990-91 winter. BG&E's annual requirements were forecasted to increase from 2 150.0 $10^6 m^3$ (76.0 Bcf) in 1990, to 2 460.0 $10^6 m^3$ (87.0 Bcf) in 1995, and to 2 600.0 $10^6 m^3$ (92.0 Bcf) in 2000.

BG&E's gas purchase strategy is to ensure that gas continues to be a competitive fuel in its franchise area. To this end, BG&E has diversified its supply options by, among other things, acquiring firm capacity on major interstate pipelines, entering into long-term gas supply arrangements, acquiring Appalachian gas-producing properties, and actively procuring gas on the spot market.

BG&E indicated that to supplement its gas supply during peak loads, and in order to cope with temporary gas supply emergencies, it relies on its propane air, liquefied natural gas, and synthetic natural gas facilities.

LILCO is a regulated combination electric and gas utility serving the Long Island, New York area.

LILCO provided a gas supply and requirements forecast for the period through to the year 2002 which demonstrated the continued need for the Canadian-sourced gas imports available through the Esso/TEMCO proposal. Gas supply deficiencies were forecasted to occur in each year through to the year 2002.

LILCO purchases long-term gas pipeline supplies from several interstate pipelines, including CNG, Tennessee, Texas Eastern Transmission Corporation and Transco. These supplies are to be supplemented with gas available through new long-term, firm incremental direct gas purchases and through the continued use of underground storage. LILCO forecasted continued economic growth in the Long Island area and therefore, continued growth in the demand for both electricity and gas. Total annual requirements were forecasted to increase from 2 436.0 $10^6 m^3$ (86.0 Bcf) in 1990, to 2 780.0 $10^6 m^3$ (98.0 Bcf) in 1995 and, to 3 100.0 $10^6 m^3$ (111.0 Bcf) in 2000.

Esso forecasted a load factor of 95 to 100 percent over the period of the proposed licence term extension. This forecast was prepared by TEMCO and is based, in part, upon TEMCO's transportation demand charge responsibility under the Esso/TEMCO gas supply arrangement. Esso noted that TEMCO's responsibility to pay the demand charges for service on the Canadian and U.S. pipeline systems, provides TEMCO with a strong financial incentive to maintain a high load factor under the Esso/TEMCO supply arrangement.

TEMCO has received authorization from the U.S. DOE/FE to import 2 125.0 $10^3 m^3/d$ (75.0 MMcfd) for the period ending 31 October 2002.

Esso argued that the three U.S. LDCs have demonstrated a need for new long-term gas supplies and that the provisions, including the take-or-penalty provisions of TEMCO/LDC contracts will ensure that the TEMCO-sourced gas will be competitive with alternative gas supplies, thus ensuring that the gas will be taken at a high load factor.

3.7 Contractual Arrangements

3.7.1 Transportation

The gas will be transported on the NOVA and TransCanada pipeline systems to the Niagara Falls, Ontario export point. From the international boundary, the gas will be transported on the pipeline systems of Tennessee, National Fuel, and

Transco to the city gates of PSE&G, BG&E and LILCO.

Esso currently has sufficient firm service pipeline capacity under contract with NOVA to deliver the full 2 125.0 $10^3m^3/d$ (75.0 MMcfd) to the Empress, Alberta delivery point. With respect to TransCanada, Esso has FS capacity for 2 125.0 $10^3m^3/d$ (75.0 MMcfd) to the Niagara Falls, Ontario delivery point until 31 October 1995. Esso indicated that it intends to negotiate a long-term extension of the existing Transportation Contract beyond 31 October 1995, failing which, Esso intends to rely on the renewal rights provision of the TransCanada FS Toll Schedule. The existing Transportation Contract was assigned by Sulpetro to Esso, effective 1 December 1987.

In the U.S, TEMCO has concluded precedent transportation agreements with National Fuel and Transco for service until 1 November 2002, subject to the receipt of the necessary regulatory approvals and to the construction of new pipeline facilities. FERC approval of the construction of all downstream pipeline facilities was expected in the spring of 1990, with firm pipeline capacity expected to be in place before 1 November 1990. The agreement with National Fuel also provides TEMCO with capacity on the Tennessee system, which National Fuel will own as part of a jointly-owned facility resulting from the Niagara Import Point Settlement.

3.7.2 Gas Sales Contract

The gas to be exported under the authority of Licence GL-82 will be sold to TEMCO at the Niagara Falls, Ontario delivery point in accordance with the terms of the Gas Sale Contract between Esso and TEMCO, dated 11 December 1980, as amended by an Amending Agreement dated 1 November 1989.

The Contract is to remain in effect until 31 October 2004, unless terminated sooner by the expiry of any Canadian or U.S. regulatory authorizations. The Contract may be terminated by either Esso or TEMCO, at any time after 31 October 2002, upon twelve months written notice.

Commencing 1 November 1989, Esso has agreed to sell TEMCO a maximum daily quantity (i.e. Contract Demand) of 2 125.0 10^3m^3 (75.0 MMcf). TEMCO is obligated to take and pay for, or nevertheless pay for, an annual quantity of gas equal to 65 percent of the Contract Demand times 365. Gas paid for, but not taken, may be taken in any subsequent contract year but only after the minimum annual volume has been taken. Esso is not obligated to deliver a volume of gas to TEMCO in excess of the Contract Demand. Esso is obligated to refund TEMCO the amount paid for any prepaid gas incurred during the last four contract years which could not be recovered prior to the expiry of the Contract.

The export price is based upon a demand/commodity pricing mechanism. The demand charge component is equal to the lesser of:

(a) the sum of the demand and commodity charges incurred by Esso in transporting the gas to the export point on the NOVA and the TransCanada systems, including the cost of any fuel gas to be supplied by Esso; or
(b) a "transportation cap" of U.S. $1.05 per Mcf, adjusted annually to reflect the absolute increase in the average, 100-percent load factor transportation cost of service of five specified U.S. gas pipelines serving the U.S. east coast (i.e. the "Representative Pipelines").

TEMCO is to re-imburse Esso for the NOVA and TransCanada demand charges regardless of the actual quantity of gas purchased.

The commodity charge component of the export price is based upon a wellhead price, which is calculated monthly and which is in turn, based upon the lesser of:

(a) the WASP of all gas sales by TEMCO, during the immediately preceding month, less the transportation costs paid by TEMCO to its pipeline transporters for delivering such gas from TEMCO's various points of purchase to TEMCO's various points of sale; or
(b) the weighted average cost of gas ("WACOG"), which is defined as the average of the "Representative Pipeline's" weighted average cost of gas as reflected in their respective "Purchase Gas Adjustment" filings with the U.S. FERC.

In determining the wellhead price, the WASP or WACOG, as the case may be, is adjusted to reflect the load factor at which the three LDC customers

took the gas from TEMCO in each of the preceding two contract years. Once established, the wellhead price is used in a formula to determine the monthly commodity charge, which can be adjusted to provide TEMCO with a financial incentive to purchase gas from Esso at, or in excess of, 60 percent of the Contract Demand.

The Contract contains two pricing reopening provisions. Firstly, the Contract contains an "intent" clause which specifies that to the extent that the contractual terms and conditions are not reasonably and fairly equivalent, on a delivered basis, to the terms and conditions pursuant to which TEMCO sells incremental, long-term firm gas at the wellhead (which gas is produced and purchased in the U.S. Gulf of Mexico and sold to U.S. east coast markets), then either Esso or TEMCO may request to reopen and renegotiate the Contract with the aim of achieving that result. Should Esso and TEMCO be unable to agree as to whether or not this overriding intention is being met and as to the manner in which the Contract should be amended to achieve that intention, the matter can be brought to arbitration by either party. Secondly, the Contract allows either Esso or TEMCO to request a review of the pricing provisions if any of TEMCO's LDC gas sales contracts, which underpin TEMCO's gas purchase from Esso, are materially amended, or are replaced by new contracts. The Contract provides that Esso and TEMCO are to share 50/50 in any positive or negative change in the value to TEMCO resulting from the amendment or the replacement contract. If the parties are unable to agree, the matter may be referred to arbitration by either party.

A "loss of market" provision in the Contract allows both Esso and TEMCO to try to find replacement markets, if one of the LDC markets is lost. In the event Esso finds a replacement market and decides to reduce the Contract Demand in the Contract, TEMCO must assign to Esso its contracted downstream U.S. transportation capacity. Once assigned, Esso would be responsible for all associated demand and commodity transportation charges. Similarly, if on any one day TEMCO is not fully utilizing its U.S. transportation capacity, TEMCO is to offer such unutilized capacity to Esso.

TEMCO has negotiated a separate gas sales arrangement with each of the three LDCs. Subject to the receipt of all associated regulatory approvals, and the construction of related U.S. pipeline facilities, each LDC has contracted to purchase gas from TEMCO through to 31 October 2002, unless the contract is further extended by mutual agreement.

Under the terms of the TEMCO/LDC gas sales arrangements, the price is to be established monthly and is to be billed on the basis of a demand/commodity pricing structure. The pricing formula in each gas sales arrangement is based upon TEMCO's WASP, which is adjusted to reflect the transportation cost differential between transporting gas to the northeast city gate from Alberta and transporting gas to the northeast city gate from the U.S. Gulf Coast, plus the 100-percent, load factor transportation rate for transporting gas from Alberta to the city gate of each LDC. The TEMCO WASP is derived by dividing TEMCO's prior months' gas sales revenues, less all applicable transportation charges associated with delivering gas to the city gates, by the total quantity of gas sold by TEMCO in that prior month.

Esso noted that the transportation cost differential adjustment to the TEMCO WASP ensures that the price of the Canadian-sourced gas to each of the three LDCs is competitive with the incremental cost of firm gas supplies originating in the U.S. Gulf Coast.

PSE&G has contracted to purchase some 934.8 $10^3m^3/d$ (33.0 MMcfd) of gas from TEMCO in accordance with a Long-Term Sales Arrangement-Memorandum of Understanding, dated 14 July 1989. The Arrangement provides PSE&G with the option to purchase an additional 1 133.0 $10^3m^3/d$ (40.0 MMcfd), in the event BG&E and LILCO are not taking their contracted quantities. The Arrangement is subject to an annual minimum purchase requirement equal to a 50-percent load factor level. If PSE&G fails to purchase the minimum annual quantities for two consecutive years, TEMCO has the right to reduce the contract quantity. PSE&G has the right to request renegotiation of the pricing provisions. Failure to reach a mutually agreeable pricing provision through renegotiation will cause the Agreement to terminate.

BG&E has negotiated a Long-Term Incremental Sales Arrangement - Agreement in Principle, dated 8 July 1988, with TEMCO to purchase some 708.2 $10^3m^3/d$ (25.0 MMcfd). The Arrangement gives BG&E the option to purchase an additional

1 354.0 $10^3m^3/d$ (47.8 MMcfd) in the event that PSE&G and LILCO are not taking their contracted quantities. The Arrangement provides for the aforementioned demand/commodity pricing structure, but is subject to certain specified price ceilings established in accordance with the load factor at which BG&E purchases the gas from TEMCO. Either party may initiate renegotiation of the pricing formula. Failure to renegotiate allows either party to terminate all or part of the Arrangement upon providing notice of not less than 150 days.

LILCO has executed a Long-Term Incremental Sales Arrangement - Agreement in Principle, dated 8 July 1988, with TEMCO to purchase some 424.9 $10^3m^3/d$ (15.0 MMcfd). The Arrangement likewise gives LILCO the option to purchase an additional 1 700.0 $10^3m^3/d$ (60.0 MMcfd) in the event that PSE&G and BG&E are not taking their contracted quantities. The Arrangement provides for summer and annual minimum take requirements equal to load factors of 50 and 65 percent, respectively. If LILCO fails to purchase the minimum annual quantities for two consecutive years, TEMCO has the right to reduce the contract quantity. The price in the Arrangement is based upon a demand/commodity price structure, subject to a price ceiling.

With respect to the "transportation cap" provision, Esso argued that since the export price is comprised of both a demand and a commodity component, and that since the Contract contains a minimum take-or-pay level, revenues from either the commodity charge component or the take-or-pay payments, when added to the demand charge revenues, should permit Esso to recover its NOVA and TransCanada transportation costs.

Esso argued that the TEMCO Contract is of commercial substance and is likely to be durable over time. Similarly, Esso argued that since the Contract was freely negotiated at arm's length, it is in the public, as well as in the private, interest. Esso noted that the Contract's durability can be seen in the fact that gas has been flowing in accordance therewith since 1980.

Esso noted that it has concluded a Licence Transfer Agreement with TEMCO, dated 1 November 1989, which provides that, upon Board and Governor In Council approval, Esso will transfer an undivided 50 percent interest in Licence GL-82 to TEMCO. Esso added that joint ownership of the Licence would facilitate the purchase, export, and resale of the imported Canadian gas under the Esso/TEMCO export proposal.

Views of the Board

The Board has reviewed the provisions of the Esso/TEMCO Contract. The Board is satisfied that the demand component of the demand/commodity pricing structure will ensure recovery of all fixed Canadian transportation costs associated with transporting the gas to the Niagara Falls, Ontario export point. The Board has accepted Esso's argument that, despite the "transportation cap" provision, the commodity charge revenue or the take-or-pay payments when added to the demand charge revenues will permit Esso to recover its NOVA and TransCanada transportation costs.

The Board is satisfied that the Contract provisions will ensure the ability of the contracting parties to respond to changing circumstances in the export market. In this regard, the Board has noted that the commodity component of the export price will always reflect the lesser of the WASP or WACOG and will therefore, ensure that the Contract is market responsive. The Board concurs with Esso that the two pricing reopening provisions, coupled with third party arbitration, will likewise ensure that export price competitiveness over the term of the Contract will be maintained. In this regard, the Board has noted the provision which provides for an increase in the unit cost of gas to TEMCO in the event the load factor in any month falls below 60 percent.

The Board accepts Esso's argument that the financial incentives inherent in the demand/commodity pricing structure with its high demand charge component; TEMCO's obligation to take and pay for, or nevertheless pay for, an annual quantity of gas equal to 65 percent of the CD times 365; and TEMCO's ability to divert the Esso imports to TEMCO's other U.S. markets, make it reasonable to expect that the gas under the Esso/TEMCO Contract will be taken.

Since the gas to be exported will only originate from reserves owned by Esso, a demonstration of producer support is not required.

3.8 Disposition

The Board has decided to issue a new gas export licence to Esso/TEMCO, as joint licence holders, and to issue a revocation order revoking Esso's export Licence GL-82, effective on the date the new export licence comes into effect. Appendix I outlines the terms and conditions of the export licence.

As more fully described in Chapter 1, in arriving at its decision the Board used its Market-Based Procedure to determine, *inter alia*, whether the volumes to be exported are surplus to reasonably foreseeable Canadian requirements. The Board has noted the absence of any complaints or opposition to the proposed export. Esso submitted an EIA, which demonstrated that the exports would have little or no impact on total production, gas prices or Canadian consumption patterns and that Canadian energy users would not have any difficulty in meeting their future energy requirements. Based on its review of these matters, the Board is satisfied that the proposed export is surplus to reasonably foreseeable Canadian requirements.

As part of its Market-Based Procedure, the Board also assessed a number of public interest factors, including gas supply, markets, gas sales contracts, and transportation arrangements associated with the proposed export.

The Board has reviewed Esso's gas reserves and productive capacity estimates and is satisfied with the adequacy of the gas supply to meet the requirements over the term of the export licence.

Having reviewed the Esso/TEMCO Contract, the Board is satisfied that it was negotiated at arm's length, that it is of commercial substance, and that it is likely to endure throughout its term.

Chapter 4

FSC Resources Limited

4.1 Application Summary

By application dated 15 February 1989, as amended, FSC has applied to the Board, under Part VI of the Act, for a new export licence to export gas at Napierville, Québec for 15 years commencing 1 March 1991. The gas would be sold to Falcon Gas for resale to three new cogeneration facilities to be constructed in, or near, Plattsburgh, N.Y. Each of the three cogeneration facilities will be designed to produce 79 MW of electric power which will be sold to New York State Electric & Gas Corporation ("NYSEG"). The thermal energy will be sold to three industrial steam hosts.

FSC has applied for an export licence with the following terms and conditions:

Term	- 15 years commencing 1 March 1991
Maximum Daily Quantity	- 1 530.0 10^3m^3 (54.0 MMcf)
Maximum Annual Quantity	- 558.45 10^6m^3 (19.7 Bcf)
Maximum Term Quantity	- 8 376.75 10^6m^3 (295.7 Bcf)

In addition, FSC has applied for a tolerance of three percent on the maximum daily quantity to account for differences and unaccounted-for losses.

The gas will originate from certain pools, fields and areas in Alberta under contract to WGML and will be transported on the NOVA and TransCanada systems to the Napierville, Québec export point. In the U.S., the gas will be transported on the new pipeline facilities to be constructed by North Country Pipeline Corporation ("North Country").

FSC is a subsidiary of Falcon Seaboard Canada Limited ("Falcon Canada"). Falcon Canada and Falcon Gas are both subsidiaries of Falcon Seaboard Energy Corporation, which is itself a subsidiary of Falcon Seaboard Resources, Inc. ("Falcon Resources"). Falcon Seaboard Power Corporation ("Falcon Power"), also a subsidiary of Falcon Resources, is the company responsible for developing the three cogeneration facilities through its subsidiaries Adirondack Power, Inc. ("Adirondack"), Saranac Energy Company, Inc. ("Saranac"), and Empire Power, Inc. ("Empire").

Falcon Seaboard Pipeline Corporation, a subsidiary of Falcon Resources, is responsible for its subsidiary North Country.

4.2 Complaints Procedure

The complaints procedure gives Canadian gas users an opportunity to object to an export proposal on the grounds that they have not had an opportunity to obtain additional supplies of gas under contract terms and conditions, including price, similar to those contained in the export proposal.

No complaints were received with respect to the FSC export proposal.

4.3 Export Impact Assessment

FSC elected to rely on the Board's most recent EIA. Based on that assessment, the applied-for export volumes would have little impact on Canadian production, consumption and prices of gas and Canadian energy users would not have any difficulty in meeting their future energy requirements as a result of the proposed exports.

4.4 Gas Supply

4.4.1 Supply Contracts

FSC has executed a 15-year Gas Sales Contract with WGML to purchase up to 1 530.0 $10^3m^3/d$ (54.0 MMcf/d). WGML will obtain the necessary gas supply for its contract with FSC through

numerous purchase contracts with TransCanada. The FSC contract is similar to, and includes the same supply assurances as, other long-term gas supply contracts with WGML. The supply assurances include the obligation for WGML to maintain a remaining reserves-to-production ratio (RR/P) above 10. Should the RR/P ratio fall below 10, WGML will be precluded from entering into new sales contracts, including renewal of existing contracts. Additionally, in times of a constraint on WGML's gas supply, FSC and other long-term sales would have priority to the available gas supply over short-term contracts. In this regard, WGML is contractually obliged to curtail short-term sales before it restricts gas supplies to its long-term sales (i.e. greater than 10 years).

The supply contract with WGML also provides FSC the option to reduce its Daily Contract Quantity ("DCQ") in return for a penalty/compensation payment to WGML. The magnitude of the payment is related to both the volume substituted and the Eastern Canada Core Market Price ("ECCMP"). FSC stated that, if it were to back down or to substitute a portion of WGML's reserves, it would do so by acquiring and developing its own reserves in Canada as opposed to contracting with other gas producers or aggregators.

Please refer to Section 7.4 of these Reasons for Decision for additional information on WGML's gas supply.

Views of Intervenors

Union was the only intervenor that provided views on FSC's gas supply. Union argued that FSC had not provided evidence of adequate gas supply because WGML may lose a significant portion of its gas supply through decontracting. Union was also of the view that FSC would have the ability to release WGML from its obligation and substitute another supply which would not be subject to the scrutiny of the Board.

Views of the Board

The Board's views on WGML's gas supply are described in detail in Section 7.4.

With respect to possible decontracting by WGML's producers, the Board recognizes that, were substantial decontracting to occur, it would have significant implications for WGML's purchasers. While cognizant of this uncertainty related to WGML's supply pool, the Board notes that WGML submitted evidence stating that it expected there to be very little effect on its supply due to decontracting. The Board also notes that no other party submitted evidence in this regard. Although some decontracting of WGML's gas supply is expected to occur, the Board recognizes the supply assurances (discussed in Section 4.4.1) provided to FSC in its gas purchase contract with WGML.

The Board also recognizes that FSC has the option to substitute a portion of WGML's supply with its own. However, considering that a penalty/compensation payment must be made to WGML and the nature of the market which is to be served by this gas supply, the Board believes that substitution would only occur if FSC had made firm alternative supply arrangements.

The Board is therefore satisfied with the adequacy of FSC's supply arrangements to meet requirements over the term of the proposed export.

4.5 Energy Removal Authorization

Gas for the FSC sale will be removed under TransCanada's Alberta removal permit #TC 85-1. The Board notes that the permit expires in 1999 and that an extension will therefore be required.

4.6 Market

The proposed export of 1 530.0 $10^3m^3/d$ (54.0 MMcfd) will be used to fuel three cogeneration facilities to be constructed in the Plattsburgh area of upper New York State. Each cogeneration facility will be capable of producing approximately 79 MW of electricity, which will be sold to NYSEG. The three cogeneration facilities will be constructed, owned and operated by Empire, Saranac and Adirondack. The cogenerators are must-run facilities, each generating approximately 657 000 MW.h of electricity annually.

The Empire cogeneration facility is to be located in an industrial park, in Beekmantown, N.Y. The industrial park is to be owned by Beekmantown Agri-Business Park, Inc. ("Beekmantown"). The facility is forecasted to consume 491.0 $10^3m^3/d$ (17.3 MMcfd) of gas. The steam hosts have been identified as Kagex, a greenhouse operator, Kitchen Pride, a mushroom grower, and TAG AGRI (USA) Development Limited, a food processor.

The Saranac cogeneration facility is to be located in Plattsburgh, N.Y. adjacent to the Georgia-Pacific Corporation ("Georgia-Pacific") tissue paper mill complex. The facility is forecasted to consume 565.0 $10^3m^3/d$ (20.0 MMcfd) of gas. The steam is to be sold to Georgia-Pacific for use in the manufacturing of tissue paper.

The Adirondack cogeneration facility is to be located adjacent to the C&A Imperial Wallcoverings, Inc. ("Imperial") manufacturing complex in Plattsburgh, N.Y., and is forecasted to consume 473.0 $10^3m^3/d$ (16.7 MMcfd) of gas. The steam is to be sold to Imperial for heating and processing.

Gasified liquid propane, stored on site, will be the back-up energy source for each of the cogeneration facilities in the event of gas supply disruptions.

The three cogeneration facilities are to run exclusively on Canadian-sourced gas to be sold by FSC to Falcon Gas for resale to each of the three cogeneration facility owners.

FSC testified that the three cogeneration facilities and the interconnecting U.S. pipeline to be constructed by North Country will be project financed, meaning that before any facilities are constructed in Canada or in the U.S., all associated contractual matters will have to be finalized and all regulatory approvals, including gas export authorization from the Board, have to be in place. FSC explained that most of the revenue resulting from the sale of the electric power to NYSEG and from the sale of the thermal energy will be used to repay the project financing. Although the project financing has not yet been completed, a number of lenders have been approached, including the same lender that backed Falcon Power's 200 MW gas-fired cogeneration facility at Big Spring, Texas. FSC expressed confidence that the necessary financial backing can be found.

Falcon Gas and North Country have filed an application with the DOE/FE for a 15-year import order. FSC indicated that a notice of the application has been issued and that a decision on its import application was anticipated in the second quarter 1990.[1]

With respect to the construction and operation of the three cogeneration facilities, each owner was to have submitted their applications to the State of New York Department of Environmental Conservation ("NYSDEC") in June 1990. Approval was expected by December 1990. Likewise, each owner was expected to receive FERC certification of QF status in the second quarter 1990.

FSC testified that Falcon Power was still at the bidding stage with respect to the major equipment (e.g. the gas and steam turbines) for the cogeneration facilities, but that orders were expected to be placed in the near future.

FSC argued that its export project is unique in that the participants are not simply proposing to export Canadian-sourced gas, but are also involved in the construction, operation and financing of the related gas pipeline and cogeneration facilities. FSC pointed out that, given the size of the total project, several contracts have to be executed and a large number of regulatory approvals secured. FSC also argued that its project represents an entirely new market for Canadian gas and offers an opportunity to develop a gas market in New York State not now served by gas and one which will be entirely dependent upon Canadian-sourced imports.

Views of Intervenors

Union argued that the FSC application was premature and should be denied because FSC had failed to furnish sufficient evidence to demonstrate the existence of an export market. Union pointed out that neither the proposed cogeneration facilities, nor the connecting gas pipeline have been approved or built. Union felt that the premature nature of the FSC export application had resulted in the filing of a number of highly conditional contracts.

Union noted that the project's financial backers require that all regulatory authorizations, including an export licence from the Board, be in place before they are willing to advance the funds for the project. Union felt that the Board should not be swayed into issuing an export licence in order to allow the pro-

1. Subsequent to the Board's rendering of its decision in respect of the subject application, FSC, by letter dated 6 June 1990, updated the Board with respect to the status of several U.S. regulatory authorizations. Among others, FSC advised the Board that:
   (a) the DOE/FE issued Falcon Gas a conditional order granting long-term import authorization for the Canadian-sourced gas; and
   (b) the FERC approved Saranac's and Adirondack's applications for certification of their respective cogeneration fascility's QF status.

ject participants to satisfy their obligations to their financial backers.

Reply Comments of FSC

In reply to the concerns raised by Union, FSC argued that its cogeneration market will be exclusively dependent upon Canadian-sourced gas. That being the case, FSC could understand why a lender, or an equity owner, would be very reluctant to advance the necessary capital to construct the cogeneration and the pipeline facilities in the absence of an export licence to permit access to that single source of gas supply.

FSC indicated that projects of its size take time to develop and to come together, given the number of contractual arrangements that must be concluded and the number of regulatory authorizations that must be secured. FSC further indicated that it would accept a sunset clause in its export licence if the Board had any concerns regarding the ripeness of FSC's export project.

4.7 Contractual Arrangements

4.7.1 Transportation

The applied-for export volumes will be transported on the NOVA and TransCanada pipeline systems to the Napierville, Québec export point. From the international border, the gas will be transported to the Plattsburgh, N.Y. area on new facilities to be constructed and operated by North Country.

WGML, the gas supplier to the FSC export project, will transport the gas on the NOVA system to the Empress, Alberta delivery point in accordance with its existing long-term, firm service transportation agreements. No new facilities are required. FSC, which will take title to the gas at Empress, Alberta, will transport the gas on the TransCanada system to the Napierville, Québec export point in accordance with a 15-year executed precedent agreement with TransCanada, using previously-approved incremental pipeline facilities, including the Napierville Extension. TransCanada has advised FSC that the Napierville Extension facilities will not be in service until 1 March 1991.

In the U.S., Falcon Gas will ship the gas on a new 26-mile pipeline to be constructed by North Country. In December 1988, an application was filed with the FERC for the necessary construction permits. FERC approval was expected in the second quarter 1990. Likewise, in December 1988, North Country filed an application with the New York State Public Service Commission ("NYSPSC") for certification of the new pipeline. NYSPSC approval for the construction of those facilities was expected in the second quarter of 1990. FSC indicated that the NYSDEC must complete its review of Falcon Seaboard's draft environmental impact statement which will consider the environmental consequences of the three cogeneration facilities and related gas pipeline and electric transmission facilities. The NYSDEC approval was expected by December 1990.

FSC indicated that since FSC, Falcon Gas and North Country are all affiliates of Falcon Resources, transportation service between Falcon Gas and North Country has not been formalized through the execution of a transportation agreement. North Country has advised Falcon Resources of its intentions to transport the gas subject to receipt of the construction certificate from the NYSPSC. A draft transportation agreement is currently under review by Falcon Resources.

4.7.2 Gas Sales Contract

FSC and Falcon Gas have executed a Gas Purchase Agreement, dated 28 June 1989, as amended by Amending Agreement dated 27 September 1989.

Under the terms of the Agreement, FSC has agreed to supply Falcon Gas with 1 530.0 $10^3m^3/d$ (54.0 MMcfd) (i.e. the "DCQ") of gas at the Napierville, Québec delivery point, for the period ending 31 October 2005, or for such period as may be required to conform with Canadian and U.S. regulatory approvals.

The Agreement recognizes FSC's right to decontract the gas supply that it has under contract with WGML and Falcon Gas' right to require FSC, upon giving reasonable notice, to exercise its option to decrease the DCQ in the gas supply contract with WGML. In the event that the gas supply from WGML is reduced, FSC and Falcon Gas agree to redetermine the gas price to reflect the cost to FSC of acquiring and delivering to Falcon Gas the substitute gas supplies. FSC acknowledged that if the pricing mechanism in the

Agreement is amended as a result of purchasing alternative gas supplies, Board approval, pursuant to subsection 35(2) of the *National Energy Board Part VI Regulations,* would first be required.

The Agreement is subject to both FSC and Falcon Gas satisfying several conditions precedent related to the completion of all contractual arrangements and the receipt of all regulatory approvals, including receipt of producer support, and of assurances that financing for the cogeneration facilities has been secured. Failure to satisfy the conditions precedent, or failure to have the conditions precedent waived, by 1 November 1992, causes the Agreement to terminate.

Under the terms of the Agreement, Falcon Gas is to pay FSC an export price that is comprised of a demand and a commodity component.

The demand component is comprised of the monthly demand charges payable by WGML and FSC for transporting the gas on the NOVA and TransCanada systems, respectively. In the event of force majeure, Falcon Gas would continue to be obligated to pay the demand charge.

The commodity component of the export price is based upon the ECCMP, less the weighted average transportation costs and charges incurred directly, or indirectly, by WGML, or by TransCanada, in moving gas on the TransCanada system from the Alberta/Saskatchewan border to the Napierville, Québec export point, less the calculated demand charge associated with gas shipments within Alberta to the Alberta/Saskatchewan border, plus the commodity charge paid by FSC for transportation service on the TransCanada system from the Alberta/Saskatchewan border to the Napierville, Québec export point, including associated gas fuel costs.

The ECCMP is equal to the weighted average net price received by WGML in accordance with the four Gas Sale Contracts negotiated by WGML with four Eastern Canadian LDCs (i.e. ICG Utilities (Ontario) Ltd., Consumers' Gas, Union, and Gaz Métropolitain, inc.).

In summary, the Agreement provides for an export price, the commodity portion of which is based upon the weighted average price per GJ, at the Alberta/Saskatchewan border, received by WGML from Eastern Canadian LDCs for gas sold by the LDCs to their core market customers, less the NOVA demand charge and reservation fee computed at 100 percent load factor.

In the event any, or all, of the WGML/Eastern Canadian LDC Gas Sales Contracts terminate and are replaced, or are amended and either FSC or Falcon Gas believes that the price payable under such an amended or replaced contract no longer reflects the price paid by an LDC for gas that it delivers to its core market customers, either FSC or Falcon Gas can require renegotiation to establish a price that reflects the price payable for gas delivered to the LDC's core market customers. The price renegotiation is subject to arbitration if the parties are unable to agree. In this regard, FSC noted that the LDC Gas Sales Contracts, which form the basis for calculating the commodity portion of the total export price to Falcon Gas, will be renegotiated effective 1 November 1990, and approximately every two years thereafter. FSC indicated that in negotiating the gas export price index both FSC and Falcon Gas believed that the two markets (i.e. the U.S. cogeneration market and the Eastern Canadian core market) offered the same features of stability and of high load factors. In addition, FSC considered the pricing mechanism to be appropriate since the market to be served will rely exclusively on Canadian-sourced gas.

FSC argued that the annual revenues generated by its export project will be sufficient to recover the Canadian intra and interprovincial transportation costs and yet provide the Canadian gas producers with an acceptable netback price. FSC noted that the pricing provision in the Agreement with Falcon Gas ensures full recovery of all Canadian demand charges associated with transporting the gas on the NOVA and TransCanada systems. FSC also believed that the indexing provision, which is based upon the weighted average price of gas sold by WGML to the Eastern Canadian LDCs, allows the export price to be market responsive since the WGML/Eastern Canadian LDC Gas Sales Contracts will be renegotiated prior to 1 November 1990 and every two years thereafter.

With respect to assurances of take, FSC pointed out that, although the Agreement does not contain a minimum take-or-pay provision, the requirement that Falcon Gas pay a monthly demand charge, whether the gas is taken or not, ensures that the gas will be taken at a high load factor. FSC added that a high load factor is assured since the three

cogeneration facilities will be entirely dependent upon Canadian-sourced gas.

4.7.3 Power Sales Agreements

The proposed sale of electricity to NYSEG will be pursuant to "Agreements" between NYSEG and Adirondack, Empire and Saranac, dated 27 April 1990. The three Agreements will continue in effect for a period of fifteen years from the date of commercial operation of the cogeneration facility and are conditioned in such a way that each party may pursue an extension of its Agreement.

The Adirondack, Empire and Saranac plants are base-load facilities, requiring NYSEG to accept and purchase the total net electrical output from each of the three cogeneration facilities. Base-load operation of the facilities requires NYSEG to pay the applicable energy charge for the energy sold by Adirondack, Empire and Saranac during both peak and off-peak periods.

The price for energy sold to NYSEG from each of the plants is identical. The sale of the electricity does not appear to require wheeling by third parties.

4.7.4 Thermal Energy Sales Agreements

The proposed steam sale from the Empire cogeneration facility will be pursuant to a Steam Purchase and Sale Agreement, dated 20 March 1990, between Empire and Beekmantown. FSC indicated that efforts were continuing in the negotiations for similar Steam Purchase and Sale Agreements with Georgia-Pacific and Imperial.

The Agreement with Empire will continue in effect for a period of fifteen years from the date of initial commercial operation of the cogeneration facility. It will be automatically extended for a period coextensive with the period that NYSEG is obligated to purchase electricity pursuant to the power sale Agreement entered into with the Empire cogeneration facility for a period up to twenty-five years after the date of initial commercial operation.

The steam hosts are obligated to purchase sufficient quantities of steam so that each of the cogeneration plants would maintain its QF status. Imperial requires the steam for heating and processing needs, Georgia-Pacific requires steam for its tissue paper mill, while Beekmantown will add value to the steam and resell it to Kagex, a greenhouse operation, Kitchen Pride, a mushroom farm and to grower TAG-AGRI (USA) Development Limited for heating and refrigeration. The Agreements provide for the development of alternative steam uses if it appears that parties to the particular agreements may fail to meet their obligations. In the event that the steam purchasers require steam when the host cogeneration plant(s) are not operating, the cogeneration operator(s) are required to operate an auxilliary boiler.

Views of the Board

The Board has reviewed the Gas Purchase Agreement between FSC and Falcon Gas, dated 28 June 1989, as amended by Amending Agreement dated 27 September 1989. The Board is satisfied that the demand component of the demand/commodity pricing structure will ensure recovery of the monthly demand charge payable by FSC to WGML for transportation service on the NOVA system and the monthly demand charge payable by FSC to TransCanada for transportation service to the Napierville, Québec export point. In this regard, the Board has noted that the demand charge is payable by Falcon Gas even in the event of force majeure.

The Board is satisfied that the commodity component of the export price, which is based on the ECCMP received by WGML in accordance with the WGML/Eastern Canadian LDC Gas Sales Contracts, will be market responsive since those Gas Sales Contracts will be renegotiated with respect to price effective 1 November 1990, and approximately every two years thereafter. In this regard, the Board notes that either FSC or Falcon Gas can seek to renegotiate the export price and that failure to agree on a renegotiated export price is subject to arbitration. The Board notes that the export pricing provision was found acceptable to WGML and to TransCanada's gas producers.

With respect to reasonable assurances that the contracted volumes will be taken, the Board accepts FSC's argument that, although the Falcon Gas/FSC Gas Purchase Agreement does not contain a minimum take-or-pay provision, the financial incentive associated with the demand-commodity pricing structure requiring payment of the demand charge regardless of the quantity of gas taken and the export market's total dependence upon Canadian-sourced gas, make it reason-

able to expect that the gas will be taken at a high load factor.

The Board has noted FSC's acknowledgement that FSC and Falcon Gas are affiliated companies and, that being the case, the Agreement was not negotiated at arm's length. However, in the circumstances of this application, the Board has accepted FSC's argument that an arm's length transaction exists since the Gas Sales Contract with WGML was negotiated at arm's length and since that Contract in turn, forms the basis of the FSC/Falcon Gas Agreement (i.e. the terms in the two contracts are almost identical).

The Board has noted Union's concern regarding the ripeness of the FSC export project and in particular, Union's position that FSC has failed to demonstrate the existence of an export market since regulatory approvals for the three cogeneration facilities and connecting U.S. gas pipeline have yet to be received.

The Board shares some of Union's concerns. In addition, the Board has noted the absence of Steam Purchase and Sale Agreements for the sale of the thermal energy to Georgia-Pacific and Imperial, without which the associated cogeneration facilities could not obtain their QF status.

However, the Board accepts FSC's argument that, given the unique nature and scope of this export project, it would be inappropriate to expect the many participants to have finalized all of the many contractual arrangements and regulatory approvals, prior to advancing an export licence application before the Board. In this regard, the Board has noted that the FSC project financing is dependent upon, among other things, NEB export authorization. Similarily, the Board has noted that no facilities will be constructed until all such contractual matters and regulatory approvals have been finalized. The Board is reasonably assured that these outstanding contractual and regulatory matters can be finalized in a timely-enough fashion to permit the gas to flow, as contemplated, on 1 March 1991.

The Board shares FSC's position that the export project offers an opportunity to develop a new export market for Canadian gas, one which has the potential to grow beyond the original three cogeneration facilities.

4.8 Disposition

The Board has decided to issue a new gas export licence to FSC, subject to approval of the Governor in Council. Appendix I outlines the terms and conditions of the export licence. The export licence includes a provision that provides that the term of the licence shall commence on 1 March 1991 and end on 28 February 1993 unless exports have commenced on or before 28 February 1993, in which case the term will end on 31 October 2005.

As more fully described in Chapter 1, in arriving at its decision the Board used its Market-Based Procedure to determine, *inter alia*, whether the volumes to be exported are surplus to reasonably foreseeable Canadian requirements. The Board has noted the absence of any complaints to the proposed export.

FSC elected to rely on the Board's EIA, which demonstrated that the exports would have little or no impact on total production, gas prices or Canadian consumption patterns and that Canadian energy-users would not have any difficulty in meeting their future energy requirements. Based on its review of these matters, the Board is satisfied that the proposed export is surplus to reasonably foreseeable Canadian requirements.

As part of its Market-Based Procedure, the Board also assessed a number of public interest factors, including gas supply, markets, gas sales contracts, and transportation arrangements associated with the proposed export.

The Board reviewed FSC's supply arrangements and is satisfied with the adequacy of the gas supply to meet the requirements over the term of the export licence. While the Board recognizes that FSC has the option to back down or substitute a portion of WGML's supply, it believes that this would be likely to occur only if FSC had made firm alternative supply arrangements. Therefore, the Board does not consider it necessary to condition FSC's licence in order to subject such alternative supply arrangements to the future scrutiny of the Board.

Having reviewed the FSC/Falcon Gas Agreement, the Board is satisfied that it is of commercial substance and that it is likely to endure throughout its term.

Ramarro Resources Inc.

5.1 Application Summary

By application dated 28 July 1989, as amended, Ramarro applied, under Part VI of the Act, for a licence to export gas at Niagara Falls, Ontario with the following terms and conditions:

Term	-	15 years commencing on 1 November 1990, or as soon thereafter as regulatory and transportation approvals are available, and ending on 31 October 2005
Maximum Daily Quantity	-	169.0 10^3m^3 (6.0 MMcf)
Maximum Annual Quantity	-	61.7 10^6m^3 (2.2 Bcf)
Maximum Term Quantity	-	936.1 10^6m^3 (33.0 Bcf)

The gas to be exported would come from established proven reserves under Ramarro's control in the Hatton Field in Saskatchewan.

The gas would be transported by the TransGas Limited ("TransGas") and TransCanada systems to the Niagara Falls, Ontario export point. In the U.S., the gas would be shipped on the Tennessee, National Fuel, Transco and Elizabethtown Gas Company ("Elizabethtown") pipeline systems.

The gas would be sold to Energy Marketing Exchange, Inc. ("EME") which will resell the gas to Kamine Milford Limited Partnership ("Kamine Milford") which owns and operates a cogeneration plant in Milford, New Jersey. The plant's electrical output will be sold to Jersey Central Power and Light Company ("JCP&L"),while the steam will be sold to Riegel Products Corporation ("Riegel Products").

5.2 Complaints Procedure

The complaints procedure gives Canadian gas users an opportunity to object to an export proposal on the grounds that they have not had an opportunity to obtain additional supplies of gas under contract terms and conditions, including price, similar to those contained in the export proposal.

No complaints were received with respect to the Ramarro export proposal.

5.3 Export Impact Assessment

Ramarro elected to rely on the Board's most recent EIA. Based on that assessment, the applied-for export volumes would have little impact on Canadian production, consumption and prices of natural gas and Canadian energy users would not have any difficulty in meeting their future energy requirements as a result of the proposed exports.

5.4 Gas Supply

5.4.1 Supply Contracts

Since Ramarro intends to supply the proposed export with gas from its own pools, no gas supply contracts were required.

5.4.2 Reserves

Table 5-1 shows that the Board's estimate of Ramarro's remaining marketable gas reserves is 19 percent lower than Ramarro's estimate. The Board's estimate, however, exceeds the applied-for term volume by 31 percent.

Ramarro has ownership in eleven land blocks in the Saskatchewan Hatton, Burstall, Bigstick and Ingebrigt Fields, which include reserves within the Upper Cretaceous Milk River, Medicine Hat and

Second White Specks Formations. Approximately two-thirds of the total difference in reserves estimates between Ramarro and the Board is found in Ramarro's land block number 9 in the Hatton Field. The Board's estimate for reserves in land block number 9 is different than Ramarro's largely due to the assignment of net pay. The Board's estimate of reserves for block 9 is about 61 percent of Ramarro's estimate. The remainder of the difference in estimates of reserves is due to net pay differences in other land blocks.

Table 5-1

Comparison of Estimates of Ramarro's Remaining Marketable Gas Reserves with the Applied-for Term Volume 10^6m^3 (Bcf)

Ramarro[1]	NEB[2]	Applied-For Volume
1 508 (53)	1 225 (43)	936 (33)

1 As of December 1989.
2 As of December 1988.

In its analysis, the Board recognized reserves for 26 areas within the 11 land blocks. Some of the land blocks have reserves in all three zones, while others have reserves in only one or two zones. None are currently in production.

In summary, the Board's estimate is lower than Ramarro's estimate but higher than the applied-for volume. This variation in estimates of reserves is due solely to differences in assignment of net pays.

5.4.3 Productive Capacity

Figure 5-1 compares the Board's and Ramarro's projections of annual productive capacity with the applied-for volumes. In its projection, Ramarro indicated that it could meet the annual requirements throughout the proposed term. The Board's projection indicates shortfalls in productive capacity beginning in 1995 and increasing in magnitude over the term. The difference in outlook is primarily attributable to the different methodologies used to project productive capacity, although another reason for the difference is the Board's lower estimate of reserves.

In preparing its productive capacity projection, Ramarro assumed exponential decline for all wells and used initial rates equal to the average of the third through fourteenth month of production. Ramarro based its assumptions on an ERCB staff study of the performance of shallow gas pools in southeastern Alberta. That study indicated rapid decline in the first few years of production, with a transition to exponential or constant percentage decline after about three years. This is representative of hyperbolic decline behaviour. The Board concurs with the use of exponential declines to project the future deliverability performance of wells in the Hatton Field, but only after the initial period of more rapid decline has occurred. The Board disagrees with Ramarro's use of exponential decline based on an initial rate established in the first year of production. The effect of Ramarro's assumptions is to project higher overall deliverability from its reserves than does the Board. The Board notes that Ramarro anticipates depletion of some 90 percent of its reserves over a 15-year period. This is somewhat greater than the level of depletion the Board would consider to be typical of low-permeability reservoirs over this time period.

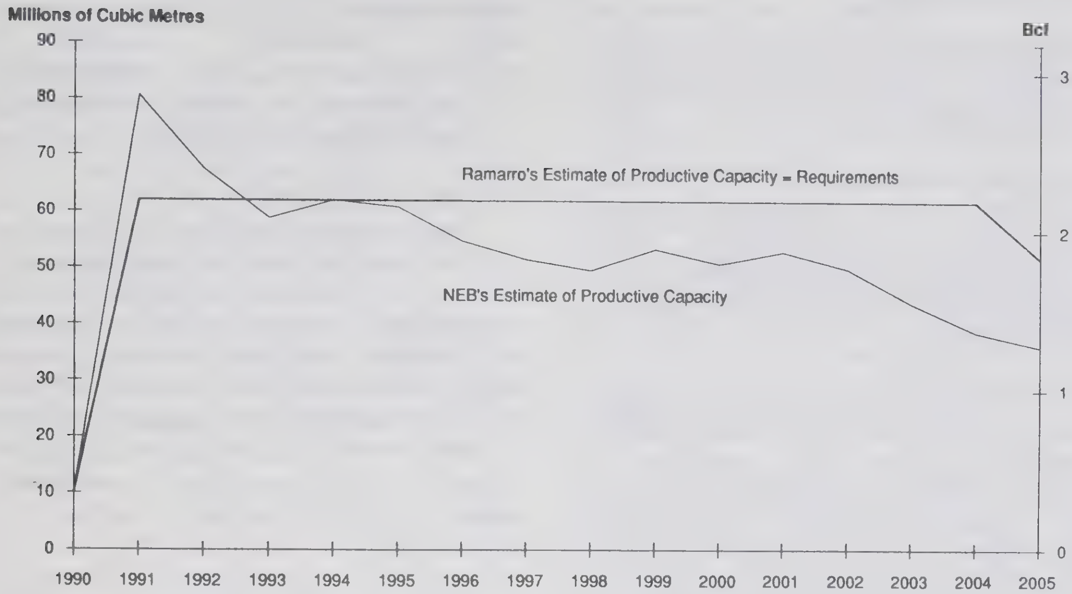
Ramarro stated that it would primarily rely on drilling infill wells in order to maintain deliverability, but would also be developing other reserves in the future. The Board incorporated Ramarro's drilling schedule in its projection and notes that potential deficiencies in supply may occur as illustrated in Figure 5-1.

Views of the Board

The Board is concerned that its projection of productive capacity is less than Ramarro's requirements throughout most of the proposed export term. The Board recognizes, however, that the difference in projections of productive capacity results from the different methodologies used to forecast productive capacity. However, considering the uncertainties in the productive capacity projection, the minor deficiencies in gas supply, and the fact that the Board's estimate of reserves significantly exceeds Ramarro's requirements, the Board is of the view that a sufficient demonstration of supply has been provided by the applicant.

Figure 5-1

COMPARISON OF RAMARRO'S & NEB'S ESTIMATES
OF ANNUAL PRODUCTIVE CAPACITY



5.5 Energy Removal Authorization

The Saskatchewan Department of Energy and Mines has recommended approval of Ramarro's removal permit application for a term of 15 years and for a term volume of 986.0 $10^6 m^3$ (35.0 Bcf).

5.6 Market

EME, a U.S.-based corporation, proposes to sell the gas to Kamine Milford for use in a 35 MW cogeneration plant located in Milford, New Jersey. The plant, which began full commercial operation in July 1989, was developed by the Kamine Development Corporation and is owned and operated by Kamine Milford.

EME will sell the gas to Kamine Milford under an executed Energy Sales Contract, dated 20 January 1988. The plant, which has QF status, is a base load facility with a gas requirement of 283.3 $10^3 m^3/d$ (10.0 MMcf/d), although on any given day it could be as high as 422.1 $10^3 m^3/d$ (14.9 MMcf/d). The plant can run on either gas or No. 2 fuel oil, the latter of which is expected to be used only 15 to 30 days per year when gas is unavailable.

When Ramarro's gas is available, EME expects to deliver 169.0 $10^3 m^3/d$ (6.0 MMcf/d), with the balance of the plant's requirement being satisfied by 113.3 $10^3 m^3/d$ (4.0 MMcf/d) from the Appalachian and Southwest regions of the U.S. under contracts with one to twelve-month terms. Currently, the plant is being supplied by Appalachian spot gas under one-year contracts.

The power purchaser, JCP&L, is engaged in the production, transmission and distribution of electric energy. The cogeneration plant will provide JCP&L with 257,880 MW.h of electricity annually under an executed Power Purchase Agreement, dated 27 April 1987. The steam will be sold to Riegel Products, a paper manufacturer, under an executed Energy Services Agreement, dated 5 February 1988.

On 15 December 1989, EME applied to the DOE/FE for import authorization.

Ramarro anticipates that EME will nominate at a 100 percent rate of take during the term of the proposed export sale.

5.7 Contractual Arrangements

5.7.1 Transportation

The gas proposed for export will be transported on the TransGas and TransCanada systems to the Niagara Falls, Ontario export point.

In the U.S., EME has contracted for firm transportation service on the Tennessee, National Fuel and Transco pipeline systems. Riegel Products is responsible for transportation on the Elizabethtown system to the Kamine Milford plant in Milford, New Jersey.

Ramarro has secured a portion of the required transportation on the TransGas system, with the balance expected to have been contracted by 15 April 1990. EME has signed a Precedent Agreement, dated 30 March 1989, with TransCanada and once all necessary authorizations are received, a FS transportation contract will be executed.

In the U.S., EME has secured firm service from the international border to the city gate of Elizabethtown under an executed Precedent Agreement between EME and Transco, dated 20 May 1988, and amended by Precedent Agreement Amendment letter dated 10 March 1989. Riegel Products has signed a transportation agreement with Elizabethtown, dated 17 April 1989, for transportation service to the Milford plant.

Additional facilities would be required on Tennessee, National and Transco for which applications have been made to the FERC. The FERC decisions are still pending.

5.7.2. Gas Sales Contract

Ramarro filed a Gas Sales Contract, dated 24 July 1989, executed by Ramarro and EME. The Contract is conditional upon both parties obtaining all regulatory approvals and firm transportation service. Either party may terminate the Contract if the conditions precedent have not been satisfied by 1 November 1991.

The Contract, which will remain in force for 15 years (i.e. until 31 December 2005), provides for the delivery and sale of 169.0 $10^3m^3/d$ (6.0 MMcf/d) on a firm basis.

The price of the gas is initially set at $2.40 U.S. per MMBtu for the first quarter of 1989 at the export point. Thereafter, the price will be adjusted periodically as follows:

(a) 40 percent of the Base Price will be adjusted each January to reflect the percentage change in JCP&L's WACOG; and

(b) 60 percent of the Base Price will be adjusted each quarter to reflect the percentage change in Transco's Spot Gas WACOG.

The Contract makes provision for renegotiation in the fifth and tenth year if either party can show actual or expected losses in excess of U.S. $50,000 per year. However, any negotiated adjustment to the then current Base Price cannot be more than 10 percent. In the event that the negotiations are unsuccessful, the matter is subject to binding arbitration.

The Contract includes a floor price equal to 98 percent of the "Alberta Average Market Price" on an annual basis, and a minimum annual take provision such that EME must take and pay for 70 percent of the annual contract volume.

Ramarro testified that even if no gas is delivered, EME must pay TransCanada's demand charges. In addition, EME has signed a financial guarantee with TransCanada guaranteeing one year of demand charges. The financial guarantee will be reviewed on an annual basis until such time as it is determined that it is no longer required. Ramarro is responsible for the TransGas transportation charges.

5.7.3 Power Sales Agreement

The proposed sale of electricity to JCP&L from the cogeneration plant, a rebuilt QF that commenced commercial operation in July 1989, will be pursuant to the Power Purchase Agreement, dated 27 April 1987. The Agreement will continue in effect for a period of fifteen years from the initial delivery date and may be extended for one five-year period.

The cogeneration plant is a base-load facility. JCP&L will pay an energy charge related to on-peak and off-peak hours, as well as, a premium for electricity delivered on peak hours during the peak season. The sale of electricity from the facility does not require wheeling by third parties.

5.7.4 Thermal Energy Sales Agreement

The proposed sale of steam to Riegel Products from the cogeneration plant will be pursuant to an Energy Services Agreement, dated 5 February 1988. The Agreement will continue in effect for a period of fifteen years following the date of initial delivery. The Agreement provides for the right to sell the thermal output to third parties.

Riegel Products operates a paper mill and is a subsidiary of the James River Corporation of Virginia which has executed a Performance Guarantee to ensure that the steam will be taken. The Guarantee ensures that the Kamine Milford cogeneration plant will maintain its QF status.

Views of the Board

The Board is satisfied that all Canadian pipeline demand charges will be recovered given that EME must pay TransCanada's demand charges regardless of whether or not the gas is shipped. As well, the Board notes the financial guarantee that EME has signed with TransCanada.

The Ramarro/EME Contract contains a pricing provision whereby the gas price will be adjusted on the basis of a combination of changes to JCP&L's annual WACOG and Transco's Spot Gas WACOG on a quarterly basis. The Contract also provides for renegotiation in the fifth and tenth years and, if necessary, for arbitration. The Board is satisfied that the Contract contains provisions which will permit adjustments to reflect changing market conditions over time.

The Contract contains a minimum take obligation equal to 70 percent of the annual contract volume. This, in addition to the fact that the demand charges must be paid regardless of whether or not the gas is delivered, leads the Board to conclude that there is a reasonable assurance that the gas will be taken by EME at a high load factor.

The Board has noted that the gas will originate from Ramarro's own gas pools and accordingly, the question of producer support is not at issue.

5.8 Disposition

The Board has decided to issue a new gas export licence to Ramarro, subject to the approval of the Governor in Council. Appendix I contains the terms and conditions of the export licence. The export licence includes a provision that the term of the licence shall commence on the date of Governor in Council approval or on 1 November 1990, whichever is the later, and end on 31 October 1992 unless exports have commenced on or before 31 October 1992, in which case the term will end on 31 October 2005.

The Board has adjusted the applied-for term quantity downward to exclude an allowance for the leap years and the additional applied-for quantity for the period 1 November to 31 December 2005, and has set the term quantity on the basis of the authorized annual quantity times the number of years in the term of the licence.

As more fully described in Chapter 1, in arriving at its decision the Board used its Market-Based Procedure to determine, *inter alia*, whether the volumes to be exported are surplus to reasonably foreseeable Canadian requirements. The Board noted the absence of any complaints or opposition to the proposed export. Ramarro elected to rely on the Board's EIA, which demonstrated that the exports would have little or no impact on total production, gas prices or Canadian consumption patterns and that Canadian energy users would not have any difficulty in meeting their future energy requirements. Based on its review of these matters, the Board is satisfied that the proposed export is surplus to reasonably foreseeable Canadian requirements.

As part of its Market-Based Procedure, the Board also assessed a number of public interest factors, including gas supply, markets, gas sales contracts, and transportation arrangements associated with the proposed export.

The Board has reviewed Ramarro's gas reserves and productive capacity estimates and is satisfied with the adequacy of the gas supply arrangements to meet the requirements over the export licence term.

Having reviewed the Ramarro/EME Contract, the Board is satisfied that it was negotiated at arm's length, that it is of commercial substance, and that it is likely to endure throughout its term.

Vector Energy Inc. [1]

6.1 Application Summary

By application dated 9 December 1989, as amended, Vector, acting as agent for seven Alberta gas producers, has applied to the Board, under Part VI of the Act, for a new gas export licence, with a term of 15 years and five months, to export gas at Niagara Falls, Ontario. The gas would be used to fuel a new 160 MW combined-cycle gas turbine cogeneration plant being constructed in Pittsfield, Massachusetts by Altresco Pittsfield, L.P. ("APLP"). APLP has sold the entire electrical output of the plant to the New England Power Corporation ("NEP") and the thermal energy to General Electric Company ("General Electric").

The gas proposed for export will be produced from the Alberta reserves owned by the seven producers and transported on the NOVA and TransCanada systems to the Niagara Falls, Ontario export point.

Vector has applied for an export licence with the following terms and conditions:

Term		- 1 July 1990 to 30 November 2005 (15 years and 5 months)
Point of Export		- Niagara Falls, Ontario
Maximum Daily Quantity	- Firm	- 892.3 10^3m^3 (31.5 MMcf)
	- Interruptible	- 141.6 10^3m^3 (5.0 MMcf)
	- Total	- 1 033.9 10^3m^3 (36.5 MMcf)
Maximum Annual Quantity	- Firm	- 325.8 10^6m^3 (11.5 Bcf)
	- Interruptible	- 51.8 10^6m^3 (1.8 Bcf)
	- Total	- 377.6 10^6m^3 (13.3 Bcf)
Maximum Term Quantity	- Firm	- 5 025.6 10^6m^3 (177.4 Bcf)
	- Interruptible	- 797.7 10^6m^3 (28.2 Bcf)
	- Total	- 5 823.3 10^6m^3 (205.6 Bcf)

In addition, Vector applied for a licence condition that would allow it the right to exceed the maximum daily quantity by 10 percent.

6.2 Complaints Procedure

The complaints procedure gives Canadian gas users an opportunity to object to an export proposal on the grounds that they have not had an opportunity to obtain additional supplies of gas under contract terms and conditions, including price, similar to those contained in the export proposal.

No complaints were received with respect to the Vector export proposal.

6.3 Export Impact Assessment

Vector elected to rely on the Board's EIA. Based on that assessment, the applied-for export volumes would have little impact on Canadian production, consumption and prices of gas and Canadian energy users would not have any difficulty in meeting their future energy requirements as a result of the proposed exports.

6.4 Gas Supply

6.4.1 Supply Contracts

Since Vector intends to supply the proposed export with gas from the pools of the seven producers, no gas supply contracts were required.

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1 As agent for:
Canadian Pioneer Energy Inc. ("Canadian Pioneer")
Ranchmen's Resources Ltd. ("Ranchmen's")
Opinac Exploration Limited ("Opinac")
Total Petroleum Canada Ltd. ("Total Petroleum")
Ulster Petroleums Ltd. ("Ulster")
Wainoco Oil Corporation ("Wainoco")
Norwest Oil & Gas Corp. ("Norwest")

All references in these Reasons for Decision to Vector are to be interpreted as referring to Vector in its capacity as agent for the above-listed seven producers.

6.4.2 Reserves

Table 6-1 shows that the Board's estimate of Vector's contracted remaining marketable gas reserves is 19 percent lower than Vector's estimate and nine percent lower than the applied-for term volume.

Table 6-1

Comparison of Estimates of Vector's Remaining Marketable Gas Reserves with the Applied-for Term Volume
10^6m^3
(Bcf)

Vector[1]	NEB[2]	Applied-for Volume[3]
5 617 (198)	4 575 (161)	5 026 (177)

1 As of 8 March 1989.
2 As of 31 December 1988.
3 Revised as of 20 March 1990.

The difference between Vector's and the Board's reserves estimates can largely be attributed to three pools in which the Board assigned smaller area and net pay than Vector. These three pools include a Caroline Lower Mannville pool, the Majeau Upper Mannville A pool and the Progress Halfway 8-10 pool. The differences in estimates of reserves also arise from differences in area assignments for single-well pools and variations in other reservoir factors. Vector indicated that there is sufficient evidence to assign full-section drainage areas to the majority of single-well pools included in the application. As noted earlier, the Board often assigns a smaller area (150 to 200 ha) to single-well pools, unless geological, geophysical, engineering or other evidence suggests that a larger area is appropriate. The Board did not find that sufficient evidence had been provided in all cases to support the area assignments submitted by Vector.

In its analysis, the Board recognized 208 gas pools, of which 74 percent are unconnected. Eighty-one percent of the total reserves comes from pools less than 100 10^6m^3 (3.5 Bcf) in size. The majority of the pools are located in the east-central portion of Alberta in Cretaceous sands.

In summary, the Board's estimate is lower than both Vector's estimate and the applied-for volume. This difference is related primarily to differences in area and net pay assignments.

6.4.3 Productive Capacity

Figure 6-1 compares both the Board's and Vector's projections of annual productive capacity with the applied-for requirements including fuel and shrinkage. Vector's projection of productive capacity is unconstrained by requirements and suggests a deficiency in supply beginning in 1996. Vector also provided a projection which reflected its contractual requirements but did not include its fuel gas requirements. If Vector's assessment of productive capacity were constrained to meet its total requirements including fuel, the resulting profile would indicate satisfactory deliverability to approximately the year 2000. The Board's projection of productive capacity indicates adequate gas supply until 1998.

Should shortfalls in productive capacity occur, each producer is required, pursuant to the Consolidated and Restated Agreement for the Sale and Purchase of Natural Gas, dated 24 June 1988, between Vector, the seven producers, and APLP ("the Consolidated Agreement"), to attempt to backstop the deficient producer with other uncontracted reserves. Vector submitted that this arrangement constituted a corporate warranty. In addition, the Consolidated Agreement requires Vector to attempt to arrange alternative supplies under the condition that the deficient producer indemnifies Vector for any incremental costs or expenses. The producer group submitted estimates of its currently available reserves to demonstrate capability to make up any shortfalls in productive capacity. However, the Board notes that those reserves are not committed to supply the proposed export. The producers could also attempt to provide additional supply through excess volume rights.

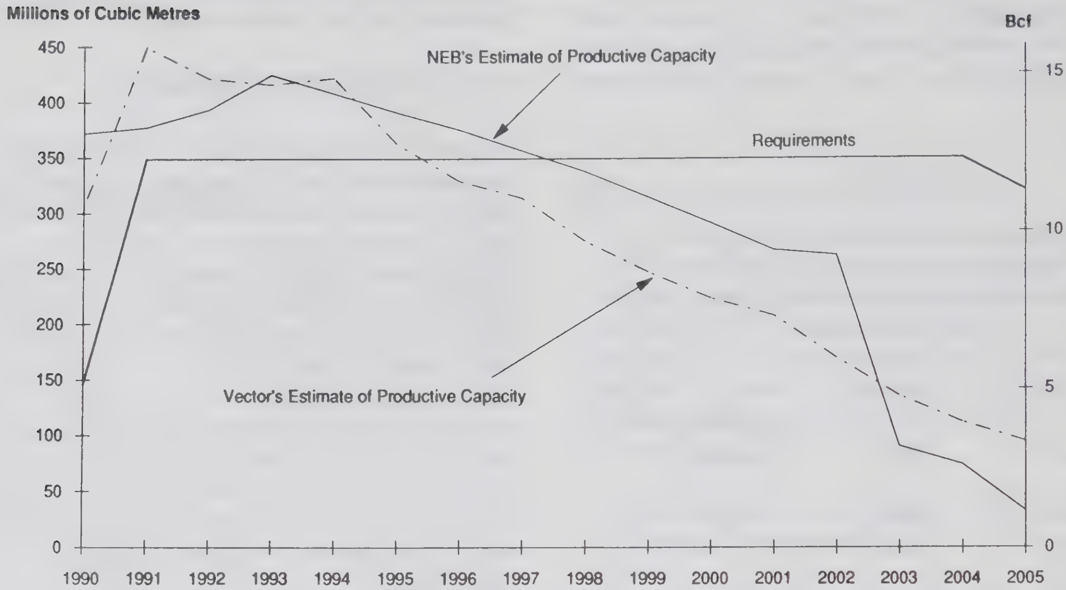
Both Vector and Altresco Inc. (APLP's general partner) argued that contracting for full deliverability throughout the proposed term was difficult to achieve and unnecessary.

Views of the Board

The Board's estimates of reserves and productive capacity suggest deficiencies relative to requirements over the term of the proposed export licence. However, the Board is of the view that the back-

Figure 6-1

COMPARISON OF VECTOR'S & NEB'S ESTIMATES OF ANNUAL PRODUCTIVE CAPACITY



stopping arrangements among the producers and the existence of a corporate warranty, substantially mitigate any potential deficiencies in productive capacity relative to requirements.

6.5 Energy Removal Authorization

Vector holds Alberta removal permit #89-95 which expires on 30 November 2004. The authorized term volume is 4 367.8 10^6m^3 (154 Bcf) which Vector acknowledged is less than the proposed export volumes. Vector stated that it would be meeting with the ERCB to further support its producers' estimates of reserves.

6.6 Market

The proposed export will be used to fuel a 160 MW combined-cycle, gas turbine, cogeneration facility currently under construction by APLP in Pittsfield, Massachusetts. The $175 million U.S. cogeneration facility, which is being constructed on General Electric's Pittsfield manufacturing and research complex, was, at the time of the GH-6-89 Hearing, 90 percent complete. Commercial operations were scheduled to start in July 1990.

The entire electrical output of the cogeneration facility is to be sold to the NEP and the entire steam output to General Electric. General Electric manufactures plastics and plastic products, mainly for the automotive industry. By purchasing the thermal energy, General Electric will be able to retire an aging, residual oil-fired boiler plant.

The APLP facility is to run exclusively on Canadian-sourced gas supplied under the Vector export proposal and is to use low sulphur No. 2 fuel oil as the back-up fuel. U.S.-sourced gas could also be used in the event that Canadian gas supply is interrupted.

NEP and its retail affiliates are controlled by the New England Electric System ("NEES"). The NEES is a member of the New England Power Pool ("NEPOOL"), a group of 95 utilities accounting for almost all of New England's electricity generation. The NEES companies account for over 20 percent of the generation available to NEPOOL. The NEES companies average annual compound growth rate since 1978 has been 3.2 percent and has averaged five percent during the past five years. Dispatch of the Pittsfield facility by the New England Power Exchange ("NEPEX"), the operating arm of NEPOOL, is expected to be in the 80-90 percent range since the dispatch is based on the incremental cost of production from the facility.

The construction financing of the APLP facility has been arranged through a Construction Loan Agreement with General Electric Capital Corporation ("GECC"). Permanent term financing is being arranged by Altresco Inc. and GECC from a group of institutional lenders led by Traveler's

Insurance Company and PruBache Capital. An affiliate of GECC is to hold a 20 percent equity position in the project.

On 5 December 1989, the DOE/FE issued an order authorizing Vector Energy (U.S.A.) Inc., Vector's U.S. subsidiary, to import 1 034 $10^3m^3/d$ (36.5 MMcfd) of Canadian gas through to 30 November 2009.

6.7 Contractual Arrangements

6.7.1 Transportation

The gas proposed for export to APLP would be transported in Alberta on the NOVA system to the point of interconnection with the TransCanada facilities for transportation to the export point at Niagara Falls, Ontario. From the international boundary, the gas would be transported by Tennessee to a new proposed interconnection with Berkshire Gas Company ("Berkshire").

Vector and each of the seven Alberta producers have executed firm transportation service agreements with NOVA for some 78 percent of the firm export volumes. Transportation service for the remaining 22 percent of the firm portion would be available on an interruptible basis. Vector anticipates being able to contract for firm transportation service for the total firm export volume of 892.3 $10^3m^3/d$ (31.5 MMcfd) by December 1990. The remaining 141.6 $10^3m^3/d$ (5.0 MMcfd) would always be shipped on an interruptible basis.

Vector, the producers, and TransCanada have concluded a 20-year Firm Service Contract. The associated TransCanada facilities are in place and service commenced in December 1989.

APLP has concluded a twenty-year precedent agreement with Tennessee for the receipt and delivery of 892.3 $10^3m^3/d$ (31.5 MMcfd). The related Tennessee pipeline facilities were approved by the FERC in April 1990. Firm capacity on the Tennessee system is expected to be available by 1 November 1990, whereas interruptible capacity is expected to be available sooner.

With respect to capacity downstream of the Tennessee system, APLP has negotiated a twenty five year transportation service agreement with Berkshire to transport the gas from the point of interconnection of the Tennessee and Berkshire systems to the Pittsfield cogeneration facility. Berkshire, a Massachusetts LDC, has agreed to construct the necessary pipeline facilities connecting its distribution system with the Pittsfield facility. Approval for the construction of the 11.5 mile Berkshire Lateral was recently granted by the Massachusetts Energy Facilities Siting Council.

6.7.2 Gas Sales Contract

In support of its application, Vector filed the executed Consolidated Agreement. The Consolidated Agreement is for a term of twenty years commencing from the date of firm delivery.

Under the terms of the Consolidated Agreement, each of the seven producers is obligated to deliver its proportionate share of the DCQ of firm gas of 892.3 $10^3m^3/d$ (31.5 MMcfd). The producers are to use their best efforts to correct any shortfalls in deliveries caused by one or more of the other producers being unable to deliver its proportionate share of the DCQ. In the event there remains a shortfall to the full DCQ required by APLP, Vector is to use its best efforts to arrange alternative supply.

Each producer has the right to supply interruptible gas, up to the maximum daily obligation under the Consolidated Agreement (i.e. 141.6 $10^3m^3/d$ (5.0 MMcfd)).

The sale and purchase of gas under the Consolidated Agreement is subject to several conditions precedent, including: receipt of all Canadian and U.S. regulatory approvals; finalization of all Canadian and U.S. transportation arrangements; and approval of the Consolidated Agreement by the U.S. electric utility purchasing the majority of the electric output of the cogeneration facility upon terms and conditions reasonably satisfactory to APLP.

The Consolidated Agreement provides for interim deliveries in the initial years (i.e. gas delivered in an interim period under interruptible transportation). If deliveries under the Consolidated Agreement have not commenced by 31 December 1990, or if the interim period has not ended on or before 31 December 1992, the Consolidated Agreement may be terminated upon written notice, by either party.

The Consolidated Agreement provides that if APLP's average takes fall below 75 percent of the DCQ over a two-year period (i.e. falls below a 75 percent load factor over two years), the producers can give notice to APLP of their intention to reduce the DCQ by 75 percent of the difference between the amount taken and 75 percent of the DCQ. APLP then has the option to either accept the reduction in the DCQ or to pay a specified reservation fee. If APLP opts for a reduction in the DCQ, it is still liable to reimburse the producers for the full amount of all transportation demand charges. Vector argued that this provision would ensure that the gas is taken at a high load factor and ensure that neither it, the producers, nor the pipelines would be at risk for any pipeline underutilization. Vector viewed this provision in the Consolidated Agreement as ensuring a minimum take of 75 percent.

The export price, which is set on a monthly basis, is comprised of a demand and a commodity charge component. The demand charge component is the sum of the transportation costs incurred by the producers on the NOVA and TransCanada systems for delivering the gas to the Niagara Falls, Ontario export point. The commodity charge component is set on the basis of a base price which is indexed to the price of No. 6 fuel oil, coal, and other gas supplies available to the New England market, particularly the electric generation market.

The Consolidated Agreement specifies that the base price may be renegotiated every five years to ensure a gas price which:

(a) is competitive with and is comparable to city gate gas prices paid for long-term, firm baseload supplies delivered to LDCs located in Connecticut, Massachusetts, and Rhode Island; and
(b) permits the APLP cogeneration plant to be dispatched as a base load fossil fuel electric generation plant operating at a 75 percent load factor.

In the event (a) and (b) are in conflict, (b) is to prevail. Arbitration is also provided for.

6.7.3 Agency Agreements

Vector has entered into two Agency Agreements. In accordance with an executed Agency Agreement, dated 12 January 1989, Vector has contracted to act as agent for Canadian Pioneer, Opinac, Ranchmen's, Ulster, Wainoco, and Norwest. Vector has executed a separate Agency Agreement, dated 21 July 1989, with Total Petroleum.

The Agency Agreements give Vector the authority to act as agent on behalf of the seven Alberta producers supplying the gas to the APLP project. In particular, through the Agency Agreements, the producers have contracted for the services of Vector to oversee and manage the administration of the Consolidated Agreement entered into between the producers, APLP, and Vector.

6.7.4 Power Sales Agreement

The proposed sale of electricity from the APLP cogeneration plant will be made pursuant to the 1989 Power Purchase Agreement, dated 9 December 1987, as amended, between APLP and NEP.[1] The Agreement is for a twenty-year period commencing with the date of operation and may be extended for an additional six-year period.

The APLP cogeneration plant will be economically dispatched by the NEPEX, the dispatching agency of the NEPOOL. Based on the incremental cost of electricity from the cogeneration facility, NEP has forecasted that the APLP cogeneration plant will be a base load unit. The electricity produced will be wheeled to NEP pursuant to the Transmission Service Agreement, dated 1 March 1989, between the Western Massachusetts Electric Company and NEP.

6.7.5 Thermal Energy Sales Agreement

The proposed sale of steam from the APLP cogeneration plant will be made pursuant to a Contract for the Purchase and Sale of Steam Energy, dated 25 April 1988, between General Electric and Altresco, acting as agent for APLP. The Contract is for an initial twenty years from the date of commercial operation of the cogeneration facility and may be extended thereafter.

General Electric will purchase sufficient quantities of steam to allow the Pittsfield cogeneration plant

1. The original Power Purchase Agreement between Altresco Pittsfield, Inc. (now known as Altresco, Inc.) and Massachusetts Electric Company was assigned to APLP and NEP.

to maintain its QF status. APLP will install an auxiliary boiler at the facility before the commencement date of operation of the 1989 Power Purchase Agreement.

Views of the Board

The Board is satisfied that the Consolidated Agreement ensures APLP's obligation to reimburse Vector and the Alberta producers for all demand charges incurred in transporting the gas in Canada, notwithstanding the actual quantity of gas taken by APLP or any claim of force majeure.

The Board is satisfied that the index mechanism in the Consolidated Agreement, whereby the commodity price of the gas is indexed to the price of No. 6 fuel, coal and gas available to the New England market, particularly the electrical power generation market, permits the export price to respond to reflect changing market conditions. In this regard, the Board has also noted that, while the export price is established monthly in accordance with this indexing mechanism, the base price may be renegotiated every five years.

The Board concurs with Vector that the take-or-release provision under which, if APLP's takes fall below 75 percent of the DCQ, the producers can either reduce their obligations to APLP or accept a reservation fee from APLP, will likely ensure a high level of take under the Consolidated Agreement. The Board notes that in the event the producers' obligations to APLP are reduced under the take-or-release provision, APLP would continue to be liable to the producers for the full transportation demand charges.

The Board is satisfied that the producers, by being a party to the Consolidated Agreement, have endorsed the terms of the export arrangement.

The Board finds that under the term of the Consolidated Agreement and the Agency Agreements, Vector has the contractual right to act as agent for the seven producers supplying gas.

6.8 Disposition

The Board has decided to issue a new gas export licence to Vector, subject to the approval of the Governor in Council. In granting a licence to Vector, as agent for the seven producers, and not to Vector in its own right, the Board recognizes that the seven producers are the joint owners of the licence which is being held on their behalf by Vector as agent. As such, the Board wishes to remind Vector and the producers that should any of the producers wish to assign its interest in the Vector/APLP export project to a third party, a licence transfer under subsection 21.1(1) of the Act would have to be authorized by the Board and approved by the Governor in Council.

The Board has not been pursuaded that it should grant the interruptible portions of the applied-for daily, annual, and term quantities. Appendix I contains the terms and conditions of the export licence to be issued. The export licence includes a provision that provides that the term of the licence shall commence on the date of Governor in Council approval or on 1 July 1990, whichever is the later, and end on 31 October 1992 unless exports have commenced on or before 31 October 1992, in which case the term will end on 31 October 2005.

As more fully described in Chapter 1, in arriving at its decision the Board used its Market-Based Procedure to determine, *inter alia*, whether the volumes to be exported are surplus to reasonably foreseeable Canadian requirements. The Board noted the absence of any complaints or opposition to the proposed export. Vector elected to rely on the Board's EIA, which demonstrated that the exports would have little or no impact on total production, gas prices or Canadian consumption patterns and that Canadian energy users would not have any difficulty in meeting their future energy requirements. Based on its review of these matters, the Board is satisfied that the proposed export is surplus to reasonably foreseeable Canadian requirements.

As part of its Market-Based Procedure, the Board also assessed a number of public interest factors, including gas supply, markets, gas sales contracts, and transportation arrangements associated with the proposed export.

The Board has reviewed Vector's gas reserves and productive capacity estimates and is satisfied with the adequacy of gas supply to meet the requirements over the term of the export licence.

Having reviewed the Consolidated Agreement, the Board is satisfied that it was negotiated at arm's length, that it is of commercial substance, and that it is likely to endure throughout its term.

Chapter 7

Western Gas Marketing Limited

7.1 Application Summary

By application dated 25 September 1989, WGML has applied, under Part VI of the Act, for a gas export licence with a term of 15 years commencing no later than 18 August 1990. The gas will be sold to Southeastern Michigan Gas Company ("Southeastern") and exported at Emerson, Manitoba.

The gas will originate from TransCanada's contracted gas reserves and will be shipped on the NOVA and TransCanada systems to the export point at Emerson, Manitoba. In the U.S., the gas will be transported on the Great Lakes Gas Transmission Company ("Great Lakes") system.

The gas will be purchased by Southeastern for system supply for resale in its franchise area in the lower peninsula in Michigan.

WGML applied for a licence with the following terms and conditions:

Term	- To commence on the date that all required approvals, licences and agreements are completed or obtained and extend for a term of 15 years following the first day of the first month succeeding that date
Maximum Daily Volume	- 424.9 10^3m^3 (15.0 MMcf)
Maximum Annual Volume	- 155.5 10^6m^3 (5.5 Bcf)
Maximum Term Volume	- 2 332.8 10^6m^3 (82.4 Bcf)

In addition, WGML applied for licence conditions that would permit it:

a) to export any volumes authorized for export, which are not actually exported during any year, during the remaining term of the licence subject to the limitations of the annual and daily volumes set out in the licence; and

b) the right to exceed the maximum daily and annual volumes by up to ten and two percent, respectively, to allow for measurement differences and unaccounted-for losses.

7.2 Complaints Procedure

The complaints procedure gives Canadian gas users an opportunity to object to an export proposal on the grounds that they have not had an opportunity to obtain additional supplies of gas under contract terms and conditions, including price, similar to those contained in the export proposal.

No complaints were received with respect to the WGML export proposal.

7.3 Export Impact Assessment

WGML chose to rely on its own EIA rather than the Board's. WGML's assessment shows that the project is unlikely to have any noticeable or measurable impacts on gas prices in domestic markets or have any effect on the ability of Canadian gas to fulfill Canadian needs at fair market prices. This is consistent with the conclusion of the Board's assessment, that is, the applied-for volumes would have little impact on Canadian production, consumption and prices of natural gas and Canadian energy users would not have any difficulty in meeting their future energy requirements as a result of the proposed exports.

7.4 Gas Supply

7.4.1 Reserves and Supply Contracts

As WGML's gas supply will be obtained from TransCanada's general supply pool, all references in this Chapter to WGML's gas supply, lands, etc. relate to TransCanada's contracted supply pool. WGML provided an estimate of TransCanada's remaining established reserves under contract to

be used to meet both existing commitments and the proposed export. Table 7-1 shows that the Board's estimate of WGML's reserves is approximately 20 percent lower than the estimate provided by WGML.

Table 7-1

Comparison of Estimates of WGML's Remaining Marketable Gas Reserves with the Applied-for Term Volume 10^9m^3 (Tcf)

WGML[1]	NEB[2]	Applied-for Term Volume[3]
653.1	520.6	2.3
(23.1)	(18.4)	(0.08)

1. As of December, 1988. This estimate of reserves includes ERCB estimates for numerous small pools which are on WGML lands but for which WGML has not submitted an estimate of reserves. Without inclusion of these pools, the WGML estimate is 603.3 10^9m^3 (21.4 Tcf).
2. As of December, 1988.
3. This represents only a very small portion of WGML's total requirements.

During its review of WGML's reserves submission, the Board noted that WGML had not submitted reserves estimates for a number of pools which appeared to be under its control. WGML was requested to review these pools and subsequently advised the Board that ERCB reserves estimates should be used for these pools until WGML has had an opportunity to review them more thoroughly. The Board has included these pools in its estimate of WGML's reserves because they appear to be under WGML's control.

Differences in the Board's and WGML's estimates of reserves arise primarily from:

(a) differences in the geological and engineering assessment of reserves for specific pools; and
(b) differences in the interpretation of WGML's contracted lands position.

The Board's estimates of reserves for a number of larger pools are lower than those of WGML, in part because performance data for some of these pools would not appear to substantiate WGML's reserves estimates based on volumetric analysis. Other reasons for these differences in estimates of reserves for large and medium sized pools relate to interpretations of recovery factor, pool size and various reservoir parameters.

A further difference between the Board's and WGML's estimates of reserves arises from the approach to reserves estimation for single-well pools. WGML generally adopts an area assignment of 256 ha (one section) to estimate reserves for a single-well pool. WGML stated that it uses a smaller single-well area where experience and knowledge support such action. As outlined earlier, the Board uses a variable area assignment, usually ranging from 150 ha to 259+ ha, but most often uses 200 ha for a single-well pool. Where the Board recognizes potential for reserves growth, a larger area is assigned to the single-well pool. Due to the large number of single-well pools in the WGML reserves portfolio, the difference in approach to reserves estimates for single-well pools leads to a significant difference in overall reserves estimates. Differences in reserves attributed to single-well pools also arise from the cumulative effect of small differences in other reservoir parameters.

WGML also tends to coalesce several smaller pools into one larger pool, which often has the effect of increasing the overall WGML estimate of reserves. The Board attempted to review the geological interpretation for many of these pools, but was in some cases unable to agree with WGML's assessment and therefore, adopted a somewhat lower estimate of reserves.

The Board and WGML also use somewhat different approaches to determine cumulative production, and hence remaining reserves, for WGML producing interests. WGML determines its remaining reserves for a pool by deducting cumulative production from dedicated lands from WGML's initial marketable reserves. While WGML undoubtedly is in the best position to determine its cumulative production from dedicated lands, this approach can have the effect of distorting the estimate of remaining WGML reserves for the pool if production by WGML to date has not been in proportion to WGML's overall interest in the pool. The Board's estimate of WGML's remaining reserves is obtained by applying WGML's percent control to the remaining reserves for the pool. Remaining reserves for the pool are determined by deducting cumulative pool

production from initial reserves. This approach assumes that remaining production will be in proportion to the ownership interests in the pool, and with the data available to the Board, is the only viable means of assigning remaining reserves to specific producer interests.

During its assessment of WGML's reserves, the Board reviewed its data regarding WGML's contractual interest in gas units. The Board found that its estimates of the unit control percentage for WGML were frequently understated. Updated information has been used to develop the Board's estimate of WGML's reserves noted above and this data is now generally in agreement with that submitted by WGML. However, differences in interpretation of WGML's contractual interests remain for a number of non-unitized pools.

In its analysis of WGML's gas supply, the Board recognized approximately 8, 000 pools, almost all of which are in Alberta. They are distributed across most of the Province and include all major producing horizons. Most of the pools are in Cretaceous zones in central and east-central Alberta. The Jurassic to Carboniferous zones include about 600 pools and are largely located in the Foothills area and north of the Deep Basin. The Devonian pools are fewer in number but contain fairly large reserves. These pools are located in the central and northern areas of Alberta.

Approximately 54 percent of WGML's reserves are contained in 100 pools, each with initial established in excess of 3 000 10^6m^3 (106 Bcf). In contrast, only 16 percent of WGML's reserves are contained in approximately 6,700 small pools, each with initial established reserves less than 100 10^6m^3 (3.5 Bcf).

In summary, the Board has updated its estimate of WGML's reserves and finds that its estimate is lower than that provided by WGML. The discrepancy in estimates of reserves arises primarily from differences in geological and engineering evaluations of specific pools but is also due to differences in interpretation of WGML's contracted lands position. The Board is cognizant of the difficulty in maintaining reliable current estimates of reserves for the large number of pools in WGML's supply portfolio and is aware that legitimate differences in technical evaluations arise due to the interpretative nature of reserves analysis. For these reasons, the Board will continue to review its reserves data on an ongoing basis in an effort to further identify and understand the reasons for the noted differences.

A further issue relevant to consideration of WGML's gas supply is the extent to which its producers have options available to them with respect to their contracts with TransCanada. WGML submitted evidence in this regard during the proceeding. None of the intervenors expressed views on this issue with respect to WGML's export application.

WGML will obtain its gas supply from TransCanada, which has contracted its supply from approximately 750 producers and suppliers. The 30 November 1988 Netback Agreement between TransCanada and its producers established new termination dates for all of TransCanada's producer contracts by extending them to the economic life of the reserves. The Agreement has been accepted in respect of over 99 percent of WGML's contracted supply and provides producers with three options related to contract reductions and/or terminations. These options available to the producer are as follows:

(a) do nothing, in which case the contracts remain as amended by the Netback Agreement and are extended to the economic life of the reserves under contract;
(b) exercise the "volume reduction entitlement option", which allows the producer, in the years following 1994, the opportunity to reduce contract volumes in a following year if a performance level of 75 percent rate of take is not achieved by TransCanada; and
(c) exercise the option to re-establish the inital contract temination date by serving notice four years prior to such date, to be effective after the 1993/94 contract year.

The second and third options are subject to there being no outstanding TOPGAS advances to the producer or any other party to the contract.

The earliest date at which certain contracts could be terminated under the third option is 1 November 1994 and notice would have to be given on or before 1 November 1990. The balance of the contracts would have termination dates in subsequent years extending beyond the year 2000.

WGML estimated that producers representing something less than five percent of the reserves and capability under contract at that time would serve four-year notices to be effective starting in the 1994/95 contract year. WGML stated that there were many reasons why a producer would prefer the first or second option. More specifically, WGML indicated that it was far more likely that producers would exercise the "volume reduction entitlement option" if the system demand for gas was at a level such that the rate-of-take performance criteria was not met because:

- many producer contracts are old, with pools nearing depletion, and therefore operating at very high effective rates of take relative to capability;
- the joint venture nature of the producing industry requires unanimity between the contracted partners as to the pros and cons of the operating environment four years later; and
- the four-year notice period involves a considerable amount of forecasting on the part of the producer as to the contract operation within the system four years hence and therefore, acts as a deterrent to the termination option.

WGML was therefore of the view that few producers would exercise the option to re-establish the initial contract termination dates by serving notice four years prior to such dates. However, at the request of the Board, WGML presented a scenario which assumed that all contracted producers serve notice on all of their contracts at the earliest possible date. Table 7-2 shows remaining reserves under contract to WGML at each contract year-end, assuming that the maximum possible number of producers exercise all their options related to contract termination at the earliest possible date. The reserves estimates also assume production over the period at capability and that historical reserves development on contracted lands continues.

7.4.2 Productive Capacity

In order to assess the adequacy of WGML's gas supply, the Board reviewed projections of productive capacity relative to requirements under three scenarios. In all cases, both WGML's and the Board's projections of productive capacity have been adjusted to reflect production of the projected level of requirements.

Table 7-2

WGML's Estimate of Remaining Reserves Under a Contract Termination Scenario[1]

Year (@ 31 October)	Remaining Reserves (PJ)	% of Reserves @ 31 Oct. 1990
1990	19 721	100
1991	18 174	92
1992	16 801	85
1993	15 588	79
1994	14 484	73
1995	9 343	47
1996	8 305	42
1997	6 755	34
1998	5 665	29
1999	4 931	25
2000	4 435	22
2001	3 753	19
2002	3 290	17
2003	2 106	11
2004	1 843	9
2005	1 265	6

1 WGML's estimate of remaining reserves under contract assuming that the maximum possible numbers of producers exercise all of their options related to contract termination at the earliest possible date.

The first scenario provides for the evergreening of both WGML's export and domestic requirements. This scenario is depicted in Figure 7-1. Under this set of assumptions, the Board's projection of productive capacity indicates that a shortfall in gas supply may begin in 1998. This compares to WGML's projection which suggests satisfactory gas supply until 1999. The Board notes that its projection of productive capacity is somewhat higher than WGML's during the first half of the projection period but decreases more rapidly than WGML's during the latter portion of the period. This difference in outlook is primarily attributable to differences in estimates of pool capability and reserves.

In the second scenario, it is assumed that only the domestic portion of WGML's requirements would be evergreened. The export portion of WGML's requirements are not evergreened and are allowed to end upon the contract expiry dates. This scenario is shown in Figure 7-2. If only domestic requirements were evergreened, WGML's projection of productive capacity indicates adequate gas supply throughout the forecast period. This compares to the Board's projection which shows that gas supply may be marginally less than requirements during the last three years of the proposed export term. As with

Figure 7-1

COMPARISON OF WGML'S & NEB'S ESTIMATES OF ANNUAL PRODUCTIVE CAPACITY TO WGML'S EVERGREENED DOMESTIC AND EXPORT REQUIREMENTS

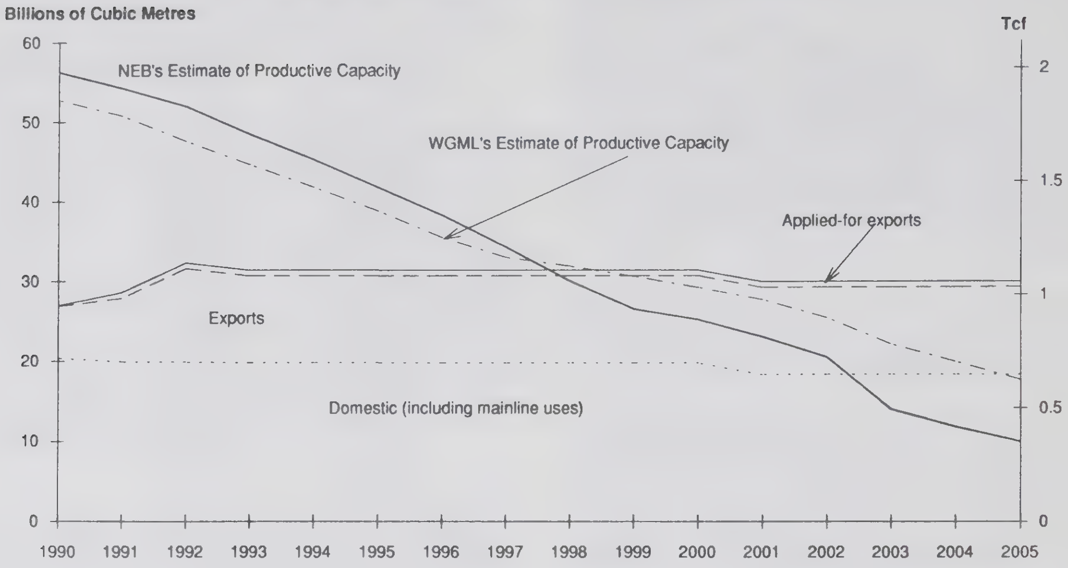
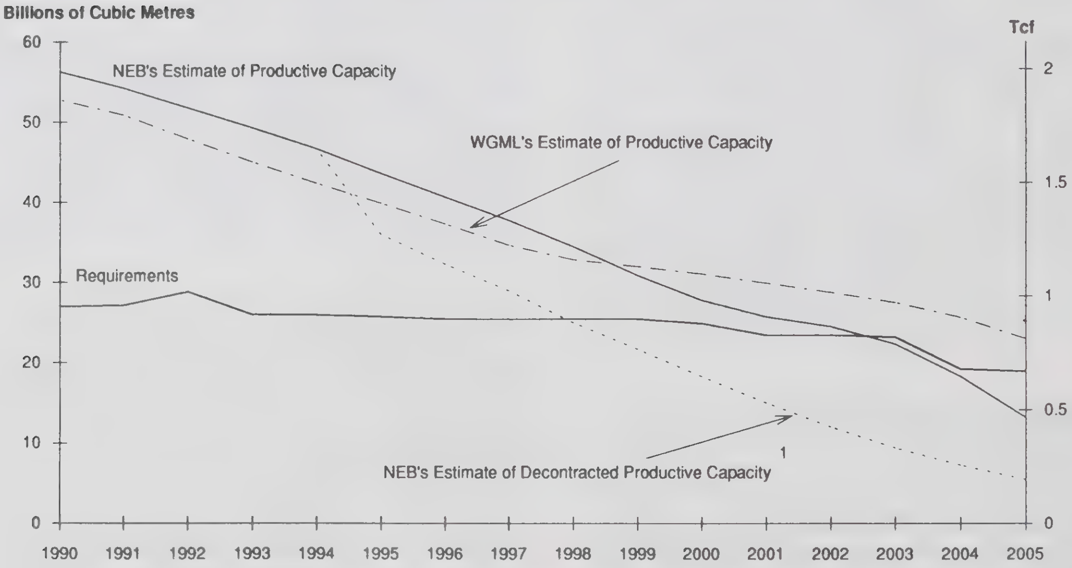


Figure 7-2

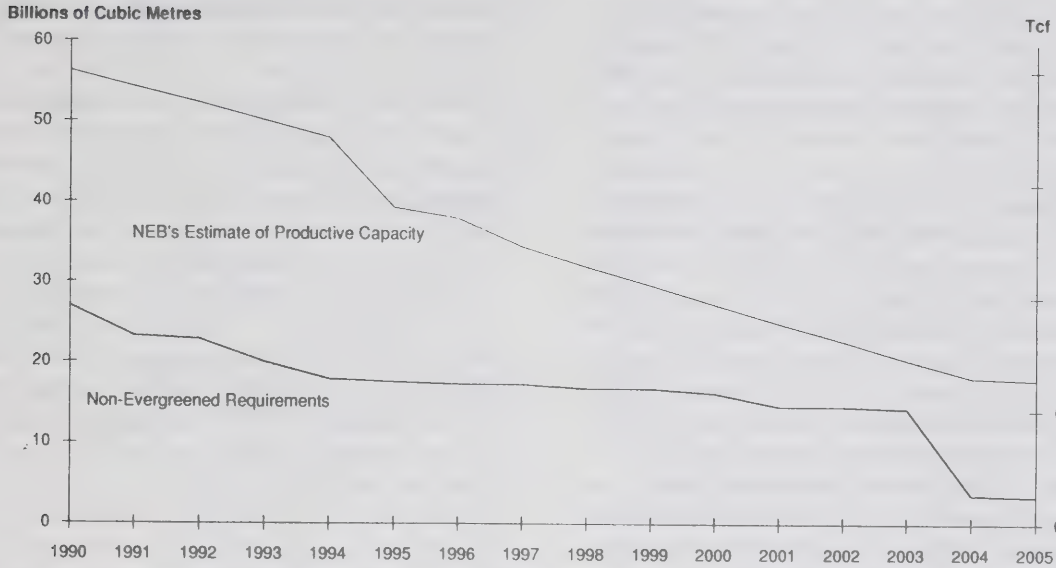
COMPARISON OF NEB'S AND WGML'S ESTIMATES OF ANNUAL PRODUCTIVE CAPACITY TO WGML'S EXISTING EXPORT AND EVERGREENED DOMESTIC REQUIREMENTS



1 Assuming the maximum possible number of producers exercise their options related to contract termination at the earliest possible date .

Figure 7-3

COMPARISON OF NEB'S ESTIMATE OF
WGML'S DECONTRACTED ANNUAL PRODUCTIVE CAPACITY
TO WGML'S NON-EVERGREENED REQUIREMENTS



the first scenario, the difference in outlook is primarily attributable to differences in estimates of pool capability and reserves. For comparative purposes, the Board has also developed an estimate of productive capacity which assumes that all contracted producers serve notice of termination on all of their contracts at the earliest possible date. If this were to occur, deficiencies in productive capacity could occur as early as 1998 if only the domestic portion of WGML's requirements were evergreened. As noted earlier, WGML considers this to be an unlikely scenario.

A third scenario was developed which also assumes that all contracted producers would serve notice of termination on all of their contracts at the earliest possible date; however, in this scenario neither WGML's export nor its domestic requirements were evergreened. This scenario is depicted in Figure 7-3. Under this set of assumptions, the Board's projection of productive capacity exceeds WGML's currently contracted requirements throughout the proposed licence term. The Board acknowledges that full decontracting of WGML's supply is unrealistic; on the other hand, this scenario does indicate that, under these assumptions, supply would be more than adequate to meet existing contractual commitments including the proposed exports.

Under the second and third scenarios, the Board has considered WGML's evidence on the impact of decontracting and has estimated the effect of those assumptions on the Board's projection of WGML's productive capacity. The Board's projection should be considered as only an approximation for illustrative purposes.

Views of The Board

The Board reviewed WGML's estimates of TransCanada's reserves and productive capacity and compared these estimates with its own.

The Board's estimate of reserves is about 20 percent lower than WGML's estimate. The difference in estimates of reserves arises primarily from differences in geological and engineering evaluations of specific pools, but also from differences in the interpretation of WGML's contracted lands position.

The Board assessed WGML's productive capacity relative to requirements under a number of scenar-

ios. The Board notes that if new exports are imposed on a base demand that assumes evergreening of both existing domestic and export sales, productive capacity estimates by both WGML and the Board fall below requirements by 1998/99 (Figure 7-1). However, based on assumed evergreening of domestic sales only, productive capacity is expected to be adequate to meet requirements throughout most of the proposed export licence term (Figure 7-2). Productive capacity is clearly adequate to meet requirements under the assumption that no evergreening of domestic or export sales is included in requirements. The Board recognizes that were substantial termination of contracts by WGML producers to occur, it could have significant implications for WGML's domestic and export purchasers. While cognizant of this uncertainty related to WGML's supply pool, the Board notes that WGML submitted evidence stating that it expected there to be very limited effect on its supply due to contract terminations and that no concerns in this regard were raised by intervenors, with respect to the WGML application.

Accordingly, the Board is satisfied that WGML has adequate gas supply to meet its currently contracted domestic and export sales requirements, including the proposed sale to Southeastern.

7.5 Energy Removal Authorization

TransCanada holds several removal permits with the majority of its reserves included in Alberta removal permit TC 85-1. The Board notes that this permit expires in 1999 and that an extension will therefore be required.

7.6 Market

Southeastern, which purchases, distributes and resells gas, is one of three gas distribution operating subsidiaries of Southeastern Michigan Gas Enterprises, Inc. supplying gas to 76,000 customers. In 1987, Southeastern sold 376.8 10^6m^3 (13.3 Bcf) of gas to residential, commercial and industrial customers. Southeastern's gas market is seasonal in nature, with approximately 80 percent of its sales occurring between November and April. Southeastern has 141.6 10^6m^3 (5 Bcf) of underground working gas storage capacity which enables it to maintain a high load factor on its gas purchases.

Southeastern testified that during the next five years, it is anticipating residential and commercial heating growth of approximately 2.3 and 1.5 percent respectively. Southeastern is forecasting no growth in the industrial firm and interruptible market sectors.

Historically, Southeastern has obtained most of its supply from Panhandle Eastern Pipeline Company ("Panhandle") under a gas supply contract which expires in October 1991. Following a decision in 1986 to diversify, strengthen and reduce its gas supply costs, Southeastern signed long-term supply and firm transportation contracts with ANR Pipeline Company ("ANR") for approximately one-third of its gas requirements. The WGML supply will make up approximately another one-third. The remainder of the gas supply will be made available under a renegotiated gas supply contract with Panhandle.

WGML noted that the sale to Southeastern represents a new market for Canadian gas. WGML is forecasting a load factor of 100 percent over the term of the applied-for export licence.

Southeastern has obtained DOE/FE import authorization for a full fifteen year term.

7.7 Contractual Arrangements

7.7.1 Transportation

The gas will be transported on the NOVA and TransCanada systems to the Emerson, Manitoba export point. In the U.S., the gas will be shipped on Great Lakes to a point of interconnection with the Southeastern delivery system.

The gas will be transported on the NOVA system, using existing capacity, under TransCanada's existing long-term, firm transportation service contracts. WGML indicated that, with respect to capacity on the TransCanada system, it will use capacity currently available under its existing transportation service contract with TransCanada in the interim while it negotiates a new fifteen-year transportation contract. WGML testified that such a transportation contract would be executed before the end of April 1990.

In the U.S., Southeastern has signed a Transportation Service Agreement, dated 12 May 1988, with Great Lakes for firm transpor-

tation. Some minor facilities construction will be required on Great Lakes for which FERC approval is expected shortly. Southeastern also stated that a direct interconnect between Great Lakes and Southeastern would have to be built. The interconnection, at Muttonville, Michigan, has been given approval in principle by the FERC and final approval is imminent. Construction will commence upon the issuance of an export licence and will take about two months to complete. Southeastern pointed out that it had also arranged back up transportation with ANR.

7.7.2 Gas Sales Contract

WGML filed an executed Precedent Agreement, dated 18 August 1989, with Southeastern to which was appended a Pro Forma Gas Purchase Contract that would be signed once all conditions precedent have been satisfied. Either party may terminate the Agreement by giving 90 days notice effective 18 August 1990 if all certificates, permits, licences, authorizations and contracts have not been obtained and accepted by all parties.

The Gas Purchase Contract is for a term of 15 years from the date of the commencement of deliveries or earlier, if any U.S. or Canadian regulatory authority so stipulates.

The Gas Purchase Contract provides for a DCV of 424.9 10^3m^3 (15.0 MMcf), as well as delivery of excess gas, on a best efforts basis, over and above the DCV, subject to existing regulatory and governmental authorizations.

The Contract contains an Annual Triggering Volume ("ATV") equal to 50 percent of the Annual Contract Volume (i.e. the DCV multiplied by the number of days in the contract year) for the first three years and 70 percent of the Annual Contract Volume thereafter.

The Contract also provides WGML with the right to permanently reduce the DCV if Southeastern fails to take the ATV in one contract year and then fails to take the deficiency volume (i.e. the difference between the ATV and the actual volume delivered in the preceding contract year) in the subsequent contract year. In the event that Southeastern fails to take the ATV, then it will pay a penalty equal to \$0.10 times the difference between the ATV and the volume actually delivered in the contract year.

The contract contains a two-part pricing structure consisting of a demand charge and a commodity charge.

The demand charge, which would be paid regardless of whether the gas is shipped, is equal to the sum of TransCanada's monthly demand toll and the average of the monthly NOVA demand charges for a 12-month period.

Southeastern will pay WGML a commodity charge based on the following equation:

$$CC = \text{Reference Price} - GLGT - \frac{DC \times 12}{365}$$

where:

(a) The Reference Price is the arithmetic average of the Delivered Alternate Supply Prices for the month under the Alternative Supply Contracts in effect in the month (i.e. volumes of firm gas under contracts signed on or after 1 July 1988 for a term of 10 years or more with an obligation to deliver 5,000 MMBtu. Such deliveries would be made on ANR or on Panhandle or would be system gas delivered out of such facilities.).

(b) The Demand Charge ("DC") is equal to the quotient that is derived by dividing the demand charge for the month by the Average Heating Value for the month.

(c) The GLGT is the 100 percent load factor to the (Great Lakes) Eastern Zone divided by the Average Heating Value for the month.

WGML testified that the export price would be competitive over the period of the proposed export, closely tracking firm U.S. gas prices in the Michigan market.

The contract allows for renegotiation at the end of any contract year and, if this is unsuccessful, either party may require that the matter be submitted to arbitration.

Views of the Board

The WGML/Southeastern Contract includes a pricing condition which provides for the recovery of NOVA and TransCanada demand charges whether or not gas is shipped. The Board is satisfied that the Contract would ensure the recovery of all fixed transportation costs.

The commodity charge component is designed to ensure that the export price responds to the price of alternative gas supplies under firm long-term contracts competing for sales in the Michigan market. To the extent that this is not the case, the Contract provides for annual renegotiation and, if necessary, arbitration. The Board is of the view that the Contract contains provisions which permit adjustments to reflect changing market conditions over the life of the Contract.

The WGML/Southeastern Contract includes an ATV provision equal to 50 percent for the first three years and 70 percent thereafter. To the extent that Southeastern fails to take the ATV, it agrees to make up the deficiency in the subsequent contract year. Failure to do so, gives WGML the right to permanently reduce the DCV. In addition, if the ATV is not taken then Southeastern must pay a penalty equal to $0.10 times the difference between the ATV and the volume actually taken.

The demand/commodity pricing structure provides for the payment of Canadian pipeline system demand charges by Southeastern whether or not the gas is shipped. This financial incentive, coupled with Southeastern's access to substantial storage capacity, leads the Board to conclude that there is a reasonable assurance that the contracted volumes will be taken.

The Board is satisfied with WGML's evidence of producer support for the proposed export sale.

7.8 Disposition

The Board has decided to issue a new gas export licence to WGML, subject to the approval of the Governor in Council. Appendix I contains the terms and conditions of the export licence. The export licence includes a provision that the term of the licence shall commence on the date of Governor in Council approval or on 18 August 1990, whichever is the later, and end on 31 October 1992 unless exports have commenced on or before 31 October 1992, in which case the term will end on 31 October 2005. The annual and term volumes are based on 365 days in each year over the fifteen-year licence term.

As more fully described in Chapter 1, in arriving at its decision the Board used its Market-Based Procedure to determine, *inter alia*, whether the volumes to be exported are surplus to reasonably foreseeable Canadian requirements. The Board noted the absence of any complaints or opposition to the proposed export. WGML submitted an EIA, which demonstrated that the exports would have little or no impact on total production, gas prices or Canadian consumption patterns and that Canadian energy users would not have any difficulty in meeting their future energy requirements. Based on its review of these matters the Board is satisfied that the proposed export is surplus to reasonably foreseeable Canadian requirements.

As part of its Market-Based Procedure, the Board also assessed a number of public interest factors, including gas supply, markets, gas sales contracts, and transportation arrangements associated with the proposed export.

In its assessment of gas supply, the Board reviewed WGML's contracted gas reserves, productive capacity estimates, and contractual arrangements and is satisfied with the adequacy of gas supply to meet the requirements over the term of the export licence.

Having reviewed the WGML/Southeastern Contract, the Board is satisfied that it was negotiated at arm's length, that it is of commercial substance, and that it is likely to endure throughout its term.

Chapter 8

Disposition

The foregoing chapters constitute our Decisions and Reasons for Decision in respect of the applications heard by the Board pursuant to Hearing Order No. GH-6-89, as amended.

R.B. Horner, Q.C.
Member

A. Côté-Verhaaf
Member

D.B. Smith
Member

Ottawa, Canada
July, 1990

Terms and Conditions of the Licences and Licence Amendment to be Issued

Terms and Conditions of the Licence to be Issued to CanStates Gas Marketing[1] and Transco Energy Marketing Company, as Joint Licence Holders.

1. The term of this Licence shall commence on the date of Governor in Council approval hereof or on 1 November 1990, whichever is the later, and end on 31 October 1992 unless exports commence hereunder on or before 31 October 1992, in which case the term will end on 31 October 2002.

2. Subject to condition 3, the quantity of gas that may be exported under the authority of this Licence shall not exceed:

   (a) for the period commencing on the date of Governor in Council approval hereof, or on 1 November 1990, whichever is the later, and ending on 31 October 2000, 1 371 100 cubic metres in any one day, or 459 300 000 cubic metres in any consecutive twelve-month period ending on 31 October;

   (b) for the period commencing on 1 November 2000, and ending on 31 October 2002, 1 371 100 cubic metres in any one day, or 500 400 000 cubic metres in any consecutive twelve-month period ending on 31 October; or

   (c) 5 593 800 000 cubic metres during the term of this Licence.

3. (a) As a tolerance, the amount that CanStates/TEMCO may export in any 24-hour period under the authority of this Licence may exceed the daily limitation imposed in condition 2 by ten percent.

   (b) As a tolerance, the amount that CanStates/TEMCO may export in any consecutive twelve-month period under the authority of this Licence may exceed the annual limitations imposed in condition 2 by two percent.

4. Gas exported under the authority of this Licence shall be delivered to the point of export near Niagara Falls, Ontario.

Terms and Conditions of the Licence to be Issued to Esso Resources Canada Limited and Transco Energy Marketing Company, as Joint Licence Holders.

1. The term of this Licence shall commence on the date of Governor in Council approval hereof or on 1 November 1990, whichever is the later, and end on 31 October 2002.

2. Subject to condition 3, the quantity of gas that may be exported under the authority of this Licence shall not exceed:

   (a) 2 125 000 cubic metres in any one day;

   (b) 775 625 000 cubic metres in any consecutive twelve-month period ending on 31 October; or

   (c) 9 307 500 000 cubic metres during the term of this Licence.

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1. To be referred to in the licence as "GasTrade Inc., Polysar Hydrocarbons Limited and Rankin Petroleum Marketing Ltd. carrying on business together in partnership as CanStates Gas Marketing".

3. (a) As a tolerance, the amount that Esso / TEMCO may export in any 24-hour period under the authority of this Licence may exceed the daily limitation imposed in condition 2 by ten percent.

   (b) As a tolerance, the amount that Esso / TEMCO may export in any consecutive twelve-month period under the authority of this Licence may exceed the annual limitation imposed in condition 2 by two percent.

4. Gas exported under the authority of this Licence shall be delivered to the point of export near Niagara Falls, Ontario.

In addition, the Board will issue a revocation order revoking export Licence GL-82 effective on the date that the aforementioned export licence comes into effect.

Terms and Conditions of the Licence to be Issued to FSC Resources Limited.

1. The term of this Licence shall commence on 1 March 1991 and shall end on 28 February 1993 unless exports commence hereunder on or before 28 February 1993, in which case the term will end on 31 October 2005.

2. Subject to condition 3, the quantity of gas that may be exported under the authority of this Licence shall not exceed:

   (a) 1 530 000 cubic metres in any one day;

   (b) 558 450 000 cubic metres in any consecutive twelve-month period ending on 31 October; or

   (c) 8 376 750 000 cubic metres during the term of this Licence.

3. (a) As a tolerance, the amount that FSC may export in any 24-hour period under the authority of this Licence may exceed the daily limitation imposed in condition 2 by ten percent.

   (b) As a tolerance, the amount that FSC may export in any consecutive twelve-month period under the authority of this Licence may exceed the annual limitation imposed in condition 2 by two percent.

4. Gas exported under the authority of this Licence shall be delivered to the point of export near Napierville, Quebec.

Terms and Conditions of the Licence to be Issued to Ramarro Resources Inc.

1. The term of this Licence shall commence on the date of Governor in Council approval hereof or on 1 November 1990, whichever is the later, and end on 31 October 1992 unless exports commence hereunder on or before 31 October 1992, in which case the term will end on 31 October 2005.

2. Subject to condition 3, the quantity of gas that may be exported under the authority of this Licence shall not exceed:

   (a) 169 000 cubic metres in any one day;

   (b) 61 700 000 cubic metres in any consecutive twelve-month period ending on 31 October; or

   (c) 925 500 000 cubic metres during the term of this Licence.

3. (a) As a tolerance, the amount that Ramarro may export in any 24-hour period under the authority of this Licence may exceed the daily limitation imposed in condition 2 by ten percent.

   (b) As a tolerance, the amount that Ramarro may export in any consecutive twelve-month period under the authority of this Licence may exceed the annual limitation imposed in condition 2 by two percent.

4. Gas exported under the authority of this Licence shall be delivered to the point of export near Niagara Falls, Ontario.

Terms and Conditions of the Licence to be Issued to Vector Energy Inc.

1. The term of this Licence shall commence on the date of Governor in Council approval hereof or on 1 July 1990, whichever is the later, and end on 31 October 1992 unless exports commence hereunder on or before 31 October 1992, in which case the term will end on 31 October 2005.

2. The quantity of gas that may be exported under the authority of this Licence shall not exceed:

   (a) 892 300 cubic metres in any one day;

   (b) 325 800 000 cubic metres in any consecutive twelve-month period ending on 31 October; or

   (c) 5 025 600 000 cubic metres during the term of this Licence.

3. (a) As a tolerance, the amount that Vector may export in any 24-hour period under the authority of this Licence may exceed the daily limitation imposed in condition 2 by ten percent.

   (b) As a tolerance, the amount that Vector may export in any consecutive twelve-month period under the authority of this Licence may exceed the annual limitation imposed in condition 2 by two percent.

4. Gas exported under the authority of this Licence shall be delivered to the point of export near Niagara Falls, Ontario.

Terms and Conditions of the Licence to be Issued to Western Gas Marketing Limited.

1. The term of this Licence shall commence on the date of Governor in Council approval hereof or on 18 August 1990, whichever is the later, and end on 31 October 1992 unless exports commence hereunder on or before 31 October 1992, in which case the term will end on 31 October 2005.

2. Subject to condition 3, the quantity of gas that may be exported under the authority of this Licence shall not exceed:

   (a) 424 900 cubic metres in any one day;

   (b) 155 100 000 cubic metres in any consecutive twelve-month period ending on 31 October; or

   (c) 2 326 500 000 cubic metres during the term of this Licence.

3. (a) As a tolerance, the amount that WGML may export in any 24-hour period under the authority of this Licence may exceed the daily limitation imposed in condition 2 by ten percent.

   (b) As a tolerance, the amount that WGML may export in any consecutive twelve-month period under the authority of this Licence may exceed the annual limitation imposed in condition 2 by two percent.

4. Gas exported under the authority of this Licence shall be delivered to the point of export near Emerson, Manitoba.